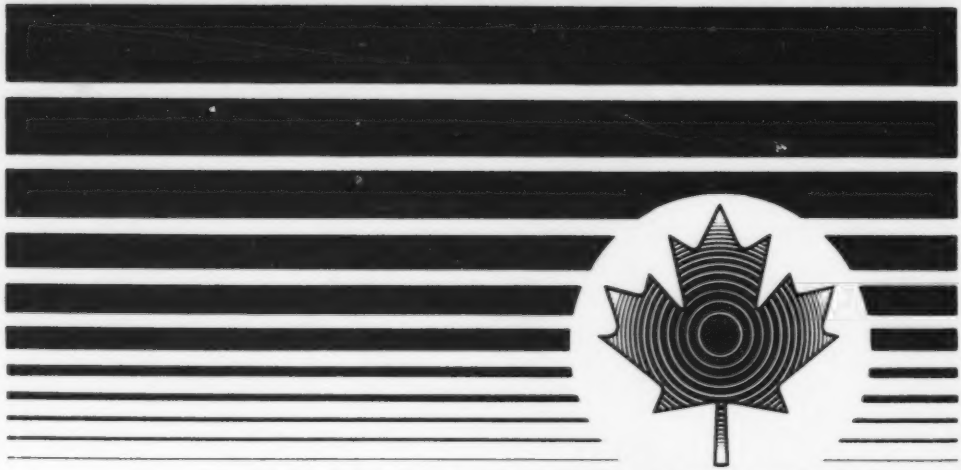
Coal And Nuclear Electricity Fuels: A Regional Analysis

Farhood Rahnama



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Preface

In this study, comparative economic analysis is used to contrast the economic advantages of nuclear and coal-fuelled stations for Canadian regions. A simplified cash flow method is used with present value techniques to yield a single levelized (or equalized) total unit energy cost over the lifetime of a generating station. This method, which is a modification of benefit-cost analysis, uses data on capital costs, fuel costs, operating and maintenance costs and lifetime energy output to calculate a single supply price (cost) for each alternative in terms of mills per kilowatt hour. The sensitivity analysis illustrates the effects of significant changes in some of the cost data on the levelized total unit energy costs.

Without sharing the remaining errors and omissions with them, I would like to thank several individuals who assisted in the preparation of this study. Special thanks to the Institute's Executive Director, Dr. G. E. Angevine, and Dr. R. W. Morrison, Senior Advisor with the Uranium and Nuclear Branch of Energy, Mines and Resources Canada, and to various individuals in the utility companies, Atomic Energy of Canada Ltd., and the review committee.

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Chapter 1

COAL AND NUCLEAR ELECTRICITY GENERATION

The comparative economics of nuclear power and coal as well as the other sources of electric power have become shrouded in controversy. The comparative economics of coal and nuclear power is a genuinely complex problem about which there can be honest differences of opinion. Plants committed today will not begin operation until six or seven years from now and are intended to have a useful life of thirty years. Furthermore, the lead time necessary for the construction permit may also take six or seven years. On such a time scale, the projection of lifetime costs is a very speculative business. Not only have construction costs of both coal and nuclear power plants escalated substantially in recent years but so too have the prices of uranium and coal. Stricter environmental controls on nuclear power and fossil fuels could have far-reaching economic effects. New scientific information on long-range environmental effects or events relating to safety or nuclear proliferation could lead to decisions having major implications for the sort of economic analysis undertaken here. In such an environment, projections must be made with considerable caution.

In this study a rather simple methodology has been used to compare and contrast the economics of nuclear and coal electric power generation. The study is based on data and information acquired from the major electric utilities in each province. Since consumption points are widely spread in Canada, one would expect some variation in the cost of electricity generation in different provinces. To capture this cost differential, the study uses provincial cost data as the basis of the economic evaluation. The cost differences within provincial boundaries are not addressed.

The study comprises four chapters followed by two appendices. Chapter 1 provides introductory remarks on coal-fired and nuclear stations. The methodology used for economic comparison is discussed in Chapter 2. Chapter 3 contains a discussion of total unit energy cost for each alternative. Sensitivity analysis is used to explain the effects of variations in key cost elements. A summary of conclusions is provided in Chapter 4 followed by Appendix A containing results of the sensitivity analysis relating to the costs of generation of

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electricity from the two alternatives. Appendix B focuses on the sensitive environmental issues concerning both coal and nuclear electricity generation. (A number of studies are available to which interested readers may refer.)[1]

1.1 Coal-Fuelled Electricity Generation

In Canada, there are several provinces which generate part of their electric energy by coal-fired power stations. This is particularly true in provinces with large deposits of coal such as Alberta. For such provinces this trend will probably continue in the foreseeable future. The increasing use of coal as a fuel for electricity generation will be stimulated both by increasing demand for electric energy and by higher prices of alternative fossil fuels. Since sufficient potential hydro sites in these provinces do not exist to satisfy their growing electric energy consumption, and oil and gas prices are rocketing upward, coal is an attractive alternative.

Table 1.1 presents a list of coal-fired power stations in service at this time, as well as coal-fired power stations committed for construction or planned. At present, Ontario has the nation's largest coal-fired generation capacity. Total in-service capacity of Ontario's coal-fired plants is more than 8 800 MW. Two more units, each with 200 MW capacity, are planned to be commissioned before the end of this decade.

Alberta, with an existing capacity of over 2 500 MW, is second in producing electric energy from coal in Canada. However, before the end of this decade more than 3 300 MW capacity will be added to Alberta's thermal power generation capacity. Saskatchewan is third in terms of coal-fired power plant capacity in Canada. At present it has over 1 000 MW capacity of electric energy generation by coal.

While Saskatchewan and Alberta use their own coal, Ontario is a major importer of thermal coal, mainly from the United States. About 98 percent of bituminous coal used in Ontario for electricity generation is imported from the United States.

New Brunswick, with an existing coal-fired generation capacity of less than 500 MW, has no plans for new coal plants in the foreseeable future. The main reason is that the Grand Lake coal deposits are not sufficient to fuel even the existing coal-fired power stations. The Grand Lake 4-unit power station is running at 45-50 percent of its capacity. The New Brunswick Electric Power Commission, jointly with the federal government, is studying the feasibility of importing coal

TABLE 1.1

MAJOR COAL-FIRED POWER STATIONS IN CANADA
BY PROVINCE

Plant	Owner	Capacity (MW)	Fuel	In-Service Year(s)
I. Operating Plants:				
Alberta				
Wabamun 1 to 4	TransAlta Utilities Corp.	582	Subbituminous	1958-68
Sundance 1 to 6	TransAlta Utilities Corp.	1 528	Subbituminous	1970-80
Battle River 1 to 4	Alberta Power	375	Subbituminous	1956-75
H. R. Milner	Alberta Power	150	Subbituminous	1973
Saskatchewan				
Boundary Dam	Sask. Power Com.	875	Lignite	1959-76
Estevan	Sask. Power Com.	70	Lignite	1944-57
Queen Elizabeth	Sask. Power Com.	240	Subbituminous	1956-72
Manitoba				
Brandon 1	Manitoba Hydro	232	Lignite	1975
Brandon 2 (2 units)	Manitoba Hydro	40	Lignite	1960
Selkirk	Manitoba Hydro	132	Lignite	1960
Amy Street	City of Winnipeg	50	Lignite	1924-57
Ontario				
J. Clark Keith	Ontario Hydro	264	Bituminous[a]	1951-53
Thunder Bay 1	Ontario Hydro	100	Bituminous	1963
Lambton 1 to 4	Ontario Hydro	2 000	Bituminous	1969
Nanticoke 1 to 8	Ontario Hydro	4 000	Bituminous	1973
Lakeview 1 to 8	Ontario Hydro	2 400	Bituminous	1961-68
Nova Scotia				
Maccan	N.S. Power Corp.	25	Bituminous	1939-49
Seaboard	N.S. Power Corp.	96	Bituminous	1951-66
Lingan 1 and 2	N.S. Power Corp.	300	Bituminous	1979-80
Trenton	N.S. Power Corp.	210	Bituminous	1951-52
New Brunswick				
Grand Lake 1 to 4	N.B. Electric Power Com.	80	Bituminous	1960-68
Dalhousie 2[b]	N.B. Electric Power Com.	200	Bituminous	1960-68
Chatam 1 to 2	N.B. Electric Power Com.	35	Bituminous	1960-68
II. Planned (Committed or Proposed):				
British Columbia				
Hat Creek	B.C. Hydro	2 000	Bituminous	1988
Alberta				
Keephills 1 to 4	TransAlta Utilities Corp.	1 500	Subbituminous	1983-86
Sheerness 1 to 2	Alberta Power	750	Subbituminous	1985-86
Genesee	Edmonton Power	750	Subbituminous	1987-88
Battle River 5	Alberta Power	375	Subbituminous	1981
Ontario				
Atikokan 1	Ontario Hydro	400	Bituminous[c]	1984-85
Thunder Bay	Ontario Hydro	300	Lignite	1981-82
Nova Scotia				
Lingan 3 to 4	N.S. Power Corp.	300	Bituminous	1984-85

SOURCE: Statistics Canada, Catalogue No. 57-206 and personal contacts.

[a]Imported Bituminous from United States.
[b]Coal Oil-fired plant.
[c]This station is planned to be built in northwestern Ontario and will burn western Canadian coal.

to fuel the Coleson Cove oil-fired installation once converted. Alberta's coal has not been considered because of the high cost of rail transportation.

In Nova Scotia, there are three relatively large coal-fired power plants. They are Trenton Station, with a 210 MW capacity, Lingan with two units in-service, each with 150 MW capacity, and Seaboard with a 96 MW capacity. Nova Scotia Power Corporation (NSPC) has two more units under construction at Lingan Station. Expected to be commissioned before 1985, these two units would have a capacity of 150 MW each.

With the addition of the first two units at Lingan Power Station the Nova Scotia Power Commission's reliance on oil for electricity generation has been reduced from about 64 percent to 40 percent. Units 3 and 4 of this station will reduce its reliance on oil for electricity generation to an insignificant level by 1990. Addition of the coal--fired units is based on the economic displacement of the present oil--fired units and the added capacity may not be required by NSPC for several years.

Assisted by new provincial and federal energy programs to persuade consumers to switch to electricity (particularly for space heating, in the residential, commercial and industrial sectors), demand for electric energy will grow significantly in the years to come. Between 1977 and 1979, electricity generation by coal grew at a 9.8 percent growth rate. This growth rate is almost twice that of total electric energy production (5.5 percent) in the same time period.[2]

The fuel cost of Canadian thermal plants, which use different types of coal, varies across the country. Table 1.2 shows the fuel cost per thousand of kilowatt hour. The cost figures vary according to location, but they have also varied through time. For most provinces, fuel cost did not change significantly in the 1960s and in the early 1970s. Like oil and gas prices, coal prices in real terms declined in that period. However, since the OPEC embargo, coal prices have started to rise, although the rate of growth is not as large as for oil prices.

As Table 1.2 shows, the price of domestic coal used in thermal electric generation in Ontario has been higher (between 50 percent in 1975 and 20 percent in 1977) than Pennsylvania coal. However, this gap has been narrowed in recent years with the advent of unit coal trains to transport low sulphur western Canadian coal. Ontario Hydro is

TABLE 1.2

FUEL COST OF ELECTRIC ENERGY PRODUCTION BY COAL, BY PROVINCE
1960-1978
(Current $/000 kW.h)

Year	Canadian Bituminous	Imported Bituminous	Sub-Bituminous	Lignite	Year	Canadian Bituminous	Imported Bituminous	Sub-Bituminous	Lignite
Nova Scotia					**Manitoba**				
1960	6.03	-	-	-	1960	134.17	-	-	3.93
1965	4.84	-	-	-	1965	14.33	-	-	4.54
1970	4.70	-	-	-	1970	44.44	-	-	4.62
1971	5.45	-	-	-	1971	34.88	-	-	4.23
1972	5.47	-	-	-	1972	34.69	-	-	4.93
1973	5.45	-	-	-	1973	34.30	-	-	5.37
1974	9.72	-	-	-	1974	35.00	-	-	6.22
1975	11.74	-	-	-	1975	35.71	-	-	6.19
1976	21.75	-	-	-	1976	40.00	-	-	8.70
1977	16.75	-	-	-	1977	14.81	-	-	10.93
1978	17.03	-	-	-	1978	-	-	-	11.96
New Brunswick					**Saskatchewan**				
1960	4.05	-	-	-	1960	-	-	4.90	1.73
1965	4.88	-	-	-	1965	-	-	3.35	1.66
1970	4.01	-	-	-	1970	-	-	3.45	1.62
1971	4.85	-	-	-	1971	-	-	3.39	1.60
1972	5.31	-	-	-	1972	-	-	3.14	1.73
1973	5.27	-	-	-	1973	-	-	4.08	1.73
1974	8.02	-	-	-	1974	-	-	4.93	2.00
1975	10.10	-	-	-	1975	-	-	6.33	2.21
1976	12.19	-	-	-	1976	-	-	8.78	2.51
1977	12.78	-	-	-	1977	-	-	10.98	2.71
1978	13.89	-	-	-	1978	-	-	11.67	2.86
Ontario					**Alberta**				
1960	-	6.23	-	-	1960	6.99	-	1.39	-
1965	3.18	3.14	-	-	1965	4.80	-	0.94	-
1970	3.93	3.49	10.31	8.07	1970	-	-	0.83	-
1971	-	4.08	-	7.02	1971	-	-	0.89	-
1972	-	4.23	-	4.78	1972	0.27	-	0.95	-
1973	-	4.58	-	6.35	1973	0.20	-	1.06	-
1974	-	5.06	-	6.22	1974	1.06	-	1.22	-
1975	12.63	8.35	-	8.98	1975	2.15	-	1.57	-
1976	14.86	10.83	-	-	1976	0.75	-	2.09	-
1977	14.32	11.67	-	-	1977	3.12	-	1.99	-
1978	16.58	12.92	-	-	1978	3.54	-	2.31	-

Source: Statistics Canada, Catalogue 57-202.

TABLE 1.3

NUCLEAR POWER PLANTS IN CANADA AS OF APRIL 1980[a]

	Owner	Net Output (MWe)
I. Operating Reactors		
Douglas Point	AECL	208
Pickering 1 to 4	Ontario Hydro	2 056
Bruce 1 to 4	Ontario Hydro	2 984
II. Reactors under Construction or Committed		
Pickering 5 to 8	Ontario Hydro	2 064
Gentilly 2	Hydro Quebec	637
Point Lepreau	New Brunswick Electric Power Commission	630
Bruce 5 to 8	Ontario Hydro	3 024
Darlington 1 to 4	Ontario Hydro	3 524

SOURCE: Energy, Mines and Resources, Report EP-80-3. Uranium in Canada, September 1980.

[a]Total operating or committed for operation by 1990 - 14 246 MWe. AECL's Gentilly 1 reactor (250 MWe) has been excluded from the list since the owner has allowed the operating licence to lapse.

TABLE 1.4

ELECTRIC ENERGY GENERATION BY URANIUM[a]

Year	Quebec		Ontario		Total Canada's Generation by Uranium[b] GW.h (A)	Total Canadian Electricity Generation GW.h (B)	A ÷ B x 100
	Generation[b] GW.h	Fuel Cost Mills/kW.h	Generation[b] GW.h	Fuel Cost Mills/kW.h			
1965	0	0	120	n/a	120	144 274	-
1970	0	0	969	n/a	969	204 723	-
1971	96	n/a	3 892	n/a	3 988	216 472	1.8
1972	622	n/a	6 117	n/a	6 739	240 213	2.8
1973	0	0	14 256	n/a	14 256	263 335	5.4
1974	0	0	13 865	n/a	13 865	280 256	4.9
1975	0	0	11 858	0.94	11 858	273 392	4.3
1976	0	0	16 430	1.14	16 430	294 043	5.6
1977	22	1.04	24 828	1.34	24 850	317 196	7.8
1978	0	0	29 435	1.61	29 435	335 654	8.8
1979	0	0	33 274	n/a	33 274	352 304	9.4

n/a - Not available.

SOURCE: Derived from Statistics Canada, Catalogue No. 57-202.

[a]Data before 1965 are not available.
[b]Net generation after deducting station service.

planning to burn western Canadian coal in its northwestern Ontario coal-fired stations.

1.2 Nuclear Plants

In 1955, Ontario Hydro undertook an agreement with Atomic Energy of Canada Limited (AECL) and Canadian General Electric Company to have a small experimental nuclear station built at Rolphton, Ontario (known as Nuclear Power Demonstration, NPD). In 1959, Ontario Hydro entered an agreement to have AECL build a prototype large-scale station with a capacity of 200 MW at Douglas Point. This station went into service in 1967 and is now part of the Bruce Nuclear Power Development.

From the NPD experience and cost estimates it became apparent that the greatest reduction in nuclear power cost could be achieved by reducing the capital cost per kilowatt of output. The best way to accomplish this reduction was to increase the size of generating units and the total capacity of the plant. The decision to go ahead with Pickering A station, with two 540 MW units, was announced in 1964. Two additional 540 MW units were announced in 1966.

Table 1.3 shows the existing, as well as the planned or committed for construction, nuclear stations. Ontario, the only province with operating nuclear reactors, has more than 5 000 MW capacity of electricity generation. Eight more units, expansions of the Pickering and Bruce Stations, are under construction and will be in service before 1987. Quebec is building its second nuclear power station, Gentilly 2, which will be commissioned in 1982, and New Brunswick's first station is to be in service in 1982.

Since the mid-1960s, electricity generation by uranium fuel has increased dramatically. The average annual growth rate of electricity generation with nuclear reactors has been more than 50 percent over the last two decades. Nuclear power generation between 1965 and 1979 is shown in Table 1.4 for Quebec and Ontario. Fuel cost data for 1975-1979 are also given in Table 1.4. As the table shows, the nuclear power share of electricity generation in Canada has been increasing in the past few years. The average annual growth rate between 1977 and 1979 was more than 10 percent. The same factor for electricity generated from coal was only 4.6 percent.

Footnotes

[1]See, for example, S. Y. Kim, "Measuring of Environmental Costs: A Survey with a Special Reference to Coal and Nuclear Generation," Ontario Hydro Economics Division, March 1981.

[2]Canada, Energy, Mines and Resources Canada, Electric Power in Canada (Ottawa: Supply and Services, 1979).

Chapter 2

ELECTRICAL ENERGY GENERATION COST CALCULATIONS

2.1 Methodology

This chapter describes the way in which the costs of both coal-fired and nuclear electricity generation were calculated. Discussion of numerical estimates of the base case for each province is found in the next chapter.

In order to make comparisons of the electric energy production costs for the two alternatives being addressed, two common methods may be used: the 'levelized cost' method and 'discounted accumulated cash flow' method.[1] The levelized cost method is based on calculating an average or 'levelized' total unit energy cost (also known as 'supply price'), i.e., the cost which could be charged each and every year of the lifetime of a plant such that the resulting revenue generated would exactly match costs incurred over the plant's lifetime. In other words, the present values of costs and corresponding revenues over the project's life would be equal. The second method involves calculating how much money would have to be invested in interest-bearing financial instruments in the reference year to pay for all the expenses of utility project construction, fueling, operating, etc., for a given number of years into the future. This second approach is a present worth calculation of the cost only, and does not look at the revenue generation.

In this study the first approach is used. Since the various projects assessed are of different production capabilities, a total unit energy cost has to be calculated for comparison purposes. This procedure is explained in detail in section 2.4.

In order to make valid economic comparisons of unit generation costs, all costs are expressed in constant dollars and real (inflation-free) interest rates are used. This is appropriate because capital expenditures are being incurred through time and the investment time periods are frequently dissimilar.

2.2 The Method

In this section, the method used to calculate the per unit cost of electricity generation from uranium and from coal is described. The unit cost of electricity generation is obtained by taking the ratio of total costs involved in generating electricity over the plant life to the total amount of electricity that can be produced during that period, i.e., the present worth of costs divided by the present worth of energy output:

$$UC_E = TC_E/Q_E$$

where UC_E represents the unit cost of electricity generation; TC_E is the total cost over the project's life; and Q_E is the corresponding total electricity which would be produced during the life of the plant. Both items on the right-hand side are expressed as present value (see section 2.4).

The main cost factors included in the total cost of either a nuclear power plant or a coal-fired station are as follows:

- Capital Cost. Capital cost is defined as payments for capital investment and includes both capital repayment and interest. The definition is the same whether or not the investment is financed from internal funds.

- Fuel Cost. Fuel cost is the cost of purchasing uranium and disposing of irradiated fuel for nuclear plants and the cost of coal for coal-fired plants.

- Operating and Maintenance Costs. These may include heavy water upkeep for nuclear plants and flue gas desulfurization (scrubbing) in the case of coal-fired stations.

The major components of the above main cost factors are discussed in more detail below. It should be noted that taxes and royalty schemes were not included because each province has its own rates and this makes the comparison across the provinces more complicated.

2.2.1 Capital Costs

The capital cost of electric generating stations, either nuclear power or coal operated, includes all direct costs paid by the utility to manufacturers and sub-contractors for materials and services in constructing the plant. It includes all of a utility's costs directly associated with the station. These include preliminary site investigation, land purchase, off-site permanent and temporary

works, site works, costs of commissioning, engineering charges and allowances to cover unforeseen conditions, interest during construction and corporate overheads, etc. These are all the costs which an electric utility incurs until the station is capable of reliably delivering electricity to the system. In the case of nuclear power plants, capital costs are very high. Although the capital cost per kilowatt of a nuclear power station may vary greatly with the size and type of reactor, there are a number of general reasons why the cost is high. In the first place, while a reactor replaces the furnace of a conventional thermal station it is still necessary to have a turbine generator. Moreover, in most nuclear stations the liquid or gas used to carry the heat away from the reactor cannot, for various reasons, be used to drive the turbo-alternator. It is necessary, therefore, to have a coolant circuit which transfers the heat from the reactor to a heat exchanger, as well as a normal boiler-turbine-condenser circuit.

The reactor itself is necessarily an expensive item even if the power output is small. Apart from the need to employ special materials and very high standards of engineering, both of which tend to lead to high costs, a reactor has to contain a certain minimum amount of fissionable material for the chain reaction to take place. Each reactor requires control equipment and instruments and a method of charging and handling the highly radioactive fuel elements. Furthermore, the intense radioactivity necessitates a thick biological shield made of concrete or similar material which has to enclose the reactor completely. These items add to the expense.

The investment in the plant and equipment required for generating electricity may be considered in two parts: those items of plant and equipment which are the same for both coal thermal plants and nuclear stations, and those items which are unique for each of them. The capital cost elements common to both coal-fired stations and nuclear power plants include:

- costs of acquiring land
- costs of building access roads
- engineering costs
- electric turbo-generator costs
- control equipment
- cost of auxiliary systems and buildings
- other equipment
- utility overhead expenses
- interest on money spent during the several years of construction

- licensing cost
- bulk transmission cost
- cooling water structures
- starting up or 'commissioning' the entire system

Apart from the above items, a coal-fired station needs a furnace to generate heat and scrubbers to reduce atmospheric pollution. A nuclear power plant requires the following additional facilities:

- the nuclear reactor
- the heavy water inventory
- spent fuel storage water pools

It is common (Ontario experience) to charge half of the initial nuclear fuel load to capital since, at the end of plant life, the fuel in the reactor at the time will, on the average, be only half used up. All remaining fuel used over the plant life, including the other half of the initial load, is charged as an operating expense.

2.2.2 Fuel Costs

The costs of fuel for nuclear power plants and for coal-fired power stations are discussed separately. Uranium is the basic energy source for nuclear plant fuel. Natural uranium cannot be used directly as a feedstock for nuclear power plants. Feedstocks in the form of mine concentrates ('yellowcake'), U_3O_8, are refined to UO_2 which is used in CANDU reactors. The fuel cost is composed of the following:

- cost of uranium mine concentrates, U_3O_8
- refinery costs, conversion to UO_2
- fuel rod fabrication cost
- irradiation and fuel disposal cost

The sum of the above four items constitutes the nuclear power plant fuel cost. When fuel is finally removed from the reactor it is stored in water-filled pools at the reactor site for a period of up to ten years. Subsequently the fuel is shipped to a fuel disposal centre. The fuel bundle is then encapsulated in a metal or ceramic container and buried below ground in a vault located in a stable geological formation. The costs of the immobilization facility, the underground vault, the associated service facilities, and of all operation and maintenance costs are all part of the fuel unit costs.

For coal-fired power stations the major components of fuel costs are:

- cost of coal at the mine
- coal transportation costs to the power plant

Total coal cost is the sum of these items. Fuel storage costs may also be added as part of the fuel cost since a stockpile of coal may be necessary to ensure that the electric generation will not be interrupted due to unexpected events that are not related to the operation of the plant itself (strikes in coal mines or transportation).

2.2.3 Operating and Maintenance Costs

These costs, generally estimated on a yearly basis, include a fixed part, independent of utilization, and a part proportional to energy output. The fixed costs include labour costs on site, costs of materials and services independent of utilization, fixed repair and maintenance cost, etc. The proportional cost includes the cost of materials consumed in operation and part of the costs of labour and materials incurred for repair and maintenance.

Operating costs also may be categorized into two parts; first, costs that are common to both coal-fired and nuclear stations and, second, those costs that are unique to either type of station. The first category of common costs includes:

- wages and salaries (and fringe benefits paid by the company) of all employees involved in administration, operation and maintenance of the station--this also includes wages and salaries of those engaged in handling and storage of fuels
- cost of services purchased from other companies or other divisions of the company
- costs of raw materials used in the operation, administration and maintenance, except fuel (and heavy water in nuclear power stations)
- development and use of computer programs
- interest and depreciation on service equipment and furniture
- interest on stored material inventories
- write-off of obsolete stored inventory items

- insurance costs
- other general expenses, including training and corporate overhead costs

Specific costs corresponding to a nuclear power station relate to heavy water upkeep.

- replacement cost of unrecovered losses, both directly through leakage and through additional losses in the upgrading of recovered leakage
- capital cost of the upgrading equipment
- operating and energy costs of the upgrading system

Another cost which could be considered is that of 'decommissioning' a plant. Because 'salvage value' of the heavy water is likely to fully fund station decommissioning costs, allowance for decommissioning may not be necessary. However, a utility company may fund an anticipated net decommissioning expense through a sinking fund, i.e., investing funds to accumulate over enough time to finance decommissioning of the nuclear plant.

Specific costs corresponding to a coal-fired plant relate to the ash management system.

- capital cost of ash management equipment and smoke stacks
- operating and energy costs of precipitation
- cost of disposing of ash

2.3 Assumptions

To keep cost comparisons of generating electric energy by nuclear power and by coal-fired operation as simple as possible the following assumptions were made:

- Demand for electricity exists for the energy produced by the power station in question at an economic or feasible electricity price.
- An electricity distribution network exists in each province with enough capacity to carry the load of the power plants considered in this study. This assumption makes the study simpler in the sense that bulk electric energy production will be considered for both plant types. It should be noted that this assumption may favour the coal-fired power stations. Since nuclear plant fuel transportation costs are relatively small, they can be built close to their consumption market. This is not the

case with coal-fired power stations. If coal deposits are not close to the market area, either the plant should be built close to the coal deposits, or coal must be transported to plants near the consumption zone. In the first case a grid system is necessary to carry the energy produced to the consumption point, requiring a large capital expenditure. In the second case, transportation costs may cancel the coal cost advantage.

- Unless specifically noted, all costs are expressed in constant 1981 dollars (real terms), representing the value of money at a given reference date. For plants already under construction or already in service, a consumer price index plus 3 percent is used to scale the costs in order to take into consideration the inflationary effects in sectors such as construction which historically have a higher price index. It would have been preferable to use specific indices for individual items, but data availability problems did not permit this. This may have the effect of understating the adjusted cost of existing plants.

- Finally, capital, fuel and operating and maintenance costs for both nuclear and coal-fired plants are based upon information developed by individual provincial electric utility companies.

2.4 Formulation of the Method

To calculate the unit cost of electric energy generation the supply price method was used. All costs incurred by an electric utility (capital, operating and fuel costs) were included at the time a utility incurred them and were expressed in present value terms. These costs were then totaled to give a total present value cost. The base date may be chosen as the date of commercial commissioning of the units considered or a common starting date may be chosen for both types of generating stations. Common (1981) starting dates were used in this study.

To calculate unit electric energy cost the following procedure was used:

Letting TC_t be the cost incurred at time t (the actual date of outlay of funds, either in real or in current dollar terms), the total discounted value of this expenditure at time zero (1981) is PV, where:

$$PV = \sum_{t=n}^{T+n} TC_t/(1 + r)t \qquad (1)$$

and T is the lifetime of the project (if the project was started before 1981 n is negative; if the project was to start after 1981 n is positive).

It should be noted that if TC is measured in real terms, it is logical to use a real discount rate, r . On the other hand, if TC is in nominal terms, r should take a nominal value, that is the real discount rate plus the inflation index in the corresponding year.[2] This study employs real costs and discount rates.

PV is the total discounted cost of a nuclear or coal-fired thermal power station, covering all costs (capital, fuel and operating and maintenance). To distribute this cost uniformly over the energy produced by the plant during its lifetime, each kilowatt-hour is assigned an average cost UC such that the discounted value of the plant's output, valued at UC, is equal to the sum of the discounted costs PV. That is,

$$PV = \sum_{t=n}^{T+n} \frac{(UC \times EG_t)}{(1 + r)^t} \qquad (2)$$

where EG_t is the amount of electricity generated at time t by the power plant in question. The unit energy cost, UC, may be calculated as follows:

$$UC = PV / \sum_{t=n}^{T+n} EG_t/(1 + r)^t \qquad (3)$$

In a more detailed form the unit cost may be stated as follows:[3]

$$UC = \frac{\sum_{t=n}^{T+n} \left(\sum_i KC_t^i + \sum_j OPC_t^j + \sum_k FC_t^k \right)/(1 + r)^t}{\sum_{t=n}^{T+n} EG_t/(1 + r)^t} \qquad (4)$$

where UC = unit cost, mills per kilowatt-hour

i,j,k = item index

t = time, years

T = lifetime of the plant from first day of project

r = discount rate

KC_t^i = capital cost, item i, year t

OPC_t^j = operating and maintenance cost, item j, year t

FC_t^k = fuel cost, item k, year t

EG_t = electricity generation, year t.

The above formula, which is referred to in the literature as 'levelized unit cost', is the discounted cash flow involved in generating electric energy in a plant divided by the discounted quantity of electric energy produced. This procedure is the same as in standard economic analysis of capital expenditure.

It should be noted that while the discounted cash flow method uses equation (1), the levelized unit energy cost approach utilizes equation (2). That is, the discounted cash flow method is only a part (one side of the equation) of the second method.

Footnotes

[1]It should be noted that by levelized cost we mean an average total unit energy production cost over the plant's life. This should not be confused with annuitized (or annualized) cost.

[2]Arithmetically the current discount rate is not equivalent to the sum of real discount rate and inflation rate, but more accurately:

$$(1 + r') = (1 + r)(1 + i)$$

where r' is nominal discount rate, r is real discount rate, and i is change in price index. In practice, however, r' = r + i is usually sufficiently accurate.

[3]The denominator on the right side is a little unexpected: that of the 'discounted energy' or 'total discounted supply'. In the literature, UC is referred to as 'supply price'. See for example, P. G. Bradley, The Economics of Crude Petroleum, North Holland, 1967. For more detailed analysis of supply price analysis see Bradley. A concise description of this method can be found in Z. C. Slagorsky, "Some Supply Price Estimates for Synthetic Crude Oil in Canada", (Calgary: Canadian Energy Research Institute), Working Paper No. 78-2. April 1978.

Chapter 3

COST COMPARISONS OF NUCLEAR AND COAL-FUELLED GENERATING STATIONS IN CANADA

3.1 Computational Assumptions and Cost Calculations

The options open to Canadian utilities vary from province to province. Newfoundland, Quebec, Manitoba and British Columbia all have economically attractive hydro potentials and Alberta and Saskatchewan have extensive coal reserves. In these provinces, both hydro power and coal offer low-cost energy options which compete with nuclear power. In Ontario and the Maritimes large-scale, low cost hydro-electric resources have largely been exploited. Ontario lacks indigenous coal resources and must use relatively expensive coal imported from the United States or transported from western Canada. The Maritimes have indigenous coal resources, but the costs of producing them are higher than those from western Canadian deposits. In these latter provinces nuclear technology may be competitive with relatively high-cost alternatives.

This chapter is devoted to calculation of the cost of generating electric energy in provinces which have, or are likely to have, coal-fired power plants and/or nuclear power stations. Provinces that are considered in this study are New Brunswick and Nova Scotia (grouped together as one region), Quebec, Ontario, Manitoba, Alberta and British Columbia.[1] First, cost figures for both alternatives, coal and nuclear, are calculated and compared. Then sensitivity analysis of the parameters is discussed. The calculations are based mainly on the methodology introduced in Chapter 2.

It should be noted that there are some difficulties with providing a precise definition of costs. Part of this difficulty is that they vary from station-to-station, from design-to-design, and from year-to-year. The cost data are mainly based on estimates and hence represent approximate values. These costs may not be sufficiently accurate for determining the basis for selling electricity. However, they are adequate for the purpose of this study. Furthermore, sensitivity analysis of the main parameters demonstrates the effects of

changes therein. As explained later, plant sizes may not be the same for all provinces--and, in general, smaller plants tend to have higher unit costs.

Among the provinces studied in this report, Ontario is the only one with a number of years of experience in nuclear power generation. Alberta on the other hand, with its vast coal deposits, has more experience in coal-fuelled power generation, using low Btu coal.

In this study only one type of nuclear reactor, the CANDU pressurized heavy water (PHW), has been assumed to be available. The CANDU type of reactor has been selected by Canadian electric utilities for a number of reasons. The CANDU reactor is a Canadian product, designed and built in Canada. This means that the technology is readily accessible to the provinces and that construction of a CANDU reactor would have spin-off effects in Canada. Furthermore, the CANDU reactor has proven itself to be the most successful reactor system in the world. For example, in terms of total lifetime capacity factor (performance) to the end of 1979, six of the top-ten reactors in the world were CANDU-PHW's.

In addition, support facilities for the CANDU reactor are readily available in Canada. These include the supply of heavy water, natural uranium fuel, and reactor components and assemblies. If another reactor type were to be chosen, services such as fuel enrichment would have to be established in Canada or purchased from foreign sources. Another advantage of the CANDU reactor is that several CANDU installations have already been housed in Canada which means quicker licensing procedures.

The breakdown of capital expenditure for both nuclear power plants and coal-fuelled power stations, unless otherwise stated, is mainly based on the percentage of total expenditure in the occurrence year shown in Table 3.1. This table shows the percentages for different construction periods from the beginning of each project.

TABLE 3.1

CONSTRUCTION PERIOD AND TOTAL EXPENDITURE BREAKDOWN
(percent)

Year	5 Years	6 Years	7 Years	9 Years	11 Years
1	5	5	5	3	1
2	15	8	7	4	2
3	30	20	12	8	5
4	40	35	20	12	8
5	10	20	30	15	13
6		12	18	25	16
7			8	20	19
8				8	20
9				4	10
10					5
11					2
	100	100	100	100	100

Where data received from the utilities were in current dollar terms for past expenditures, the incurred amounts were escalated with an index equivalent to the general price index plus an additional 3 percent. The latter has been added to cover inflation in industries, such as construction, which have experienced a higher rate of inflation than the economy as a whole. For general inflation forecasts, data in the federal government's October 1980 National Energy Program have been utilized. Table 3.2 shows the price index used in the above study. Calculation of the total unit energy cost for both coal and nuclear generation are based on information supplied by utility companies and by the Atomic Energy of Canada Ltd. (AECL).

TABLE 3.2

PRICE INDEX, HISTORICAL DATA AND FORECASTS
(1981 = 1.00)

Year	Index	Year	Index
1970	3.036	1978	1.341
1971	2.858	1979	1.231
1972	2.644	1980	1.120
1973	2.359	1981	1.000
1974	2.032	1982	0.900
1975	1.783	1983	0.815
1976	1.591	1984-2020	8% inflation/yr.
1977	1.449		

SOURCE: The National Energy Program; Statistics Canada.

Finally, for simplicity, it was assumed that the fuel cost for a coal-fuelled station will grow at 1 percent per year in real terms until 1990 and at 2 percent per year after 1990; the uranium costs are assumed to remain constant until 1990 and grow at 1 percent (real) per year after 1990. Operating and maintenance costs are assumed to grow at a rate of 1 percent above the inflation rate until 1990 and remain constant after 1990 for both coal-fired and nuclear power stations. The increase in the coal and uranium prices seems reasonable in relation to the long-range forecast of the price of crude oil, which is generally somewhat higher. However, given the foreseen demand and supply situations vis-a-vis coal and uranium, the assumed slower growth rates were felt to be more appropriate for those commodities.

In calculations of total unit energy cost, a capacity factor of 80 percent was used for both nuclear and coal-fuelled power stations over 35 years of their useful life in the base case. This capacity factor may be high for coal-fuelled power stations. However, for nuclear stations the capacity factor is usually in this range.[2] Effects of the reduction of this parameter are examined in Appendix A.

The discount rate used in calculation of the base case was 5 percent in real terms. A 5 percent rate is within the range of the long-run real cost of capital which utilities have faced in financial markets, i.e., the market rate adjusted for inflation. From a utility's perspective, this rate represents the cost of capital, but to society it may not adequately represent the cost of investing in

electric power facilities. For this reason the effects of different discount factors on unit energy cost are examined in the sensitivity analysis section (3 percent and 8 percent).

The fuel costs of coal-fuelled power plants were calculated on the basis of 13,000 Btu per pound of bituminous coal. Coal costs and heat rates for plants in each region are given if available. The fuel costs for nuclear plants are based on a uranium (U_3O_8) price of $34 per pound.[3] This may over estimate the unit energy cost produced by the nuclear alternative because the uranium market is currently facing an excess supply situation. (Some utility companies, both in Canada and the United States, have been supplying uranium to the market from their long-term contracts with mining companies.) Nuclear fuel costs include allowances for waste, management, transportation and spent fuel disposal.

Note that the original cost estimates could be far from the actual expenditures. For example, total investment expenditure for the Gentilly 2 power station in Quebec is estimated to be $1.3 billion (rather than its original $0.8 billion estimate). The main reasons for higher costs have been related to delays in construction caused by problems such as in-situ retubing of the boiler (which was damaged during heat treatment at the fabrication plants), regulatory issues and labour problems.

3.1.1 Atlantic Region

At present there are three main coal-fuelled power stations in New Brunswick, namely, Grand Lake, Chathan and Dalhousie. The latter two stations burn coal as well as light and heavy oil. It was planned that the Chathan station would use only light and heavy oil in the 1981-1982 budget year. The main reason is a shortage of economical coal deposits in the province. Coal deposits from the Grand Lake area support only 45 percent to 50 percent of the Grand Lake power station. The New Brunswick Electric Power Commission (NBEPC) is considering purchasing coal from British Columbia via the Panama Canal to supply fuel for the existing fossil-fuelled power stations in this province. Because of the coal supply problem the NBEPC has no plans to construct any new coal-fuelled stations in the foreseeable future.

Construction of a nuclear power station, Point Lepreau, with a 630 MW capacity, is in progress to meet electricity requirements.[4] The in-service date of the plant has been delayed for various reasons such as labour problems. However, it is to become operational during 1982.

In Nova Scotia, the main source of electric energy at present is the conventional thermal generating station. To meet foreseen electricity demand the Nova Scotia Power Corporation (NSPC) is building a coal-fuelled power station at Lingan, with 3 x 150 MW capacity. The Corporation owns a number of coal-fuelled power stations which use Nova Scotia's bituminous coal. NSPC at present has no plans to erect a nuclear power station. However, it is conceivable that Nova Scotia might participate in the construction of an additional nuclear unit at Point Lepreau in New Brunswick.

Electric energy demand in Newfoundland is primarily met by hydro-electric generation. Since there are still a number of undeveloped hydro sites in Newfoundland (Labrador), there are no plans to construct coal or nuclear plants to supply part of the electric energy demand in the near future.

As representative of a nuclear station in Atlantic region, the cost data for Point Lepreau in New Brunswick are used. For coal-fuelled plants the cost information on the Lingan station is used. In the first case, the unit energy cost calculated provides a good approximation for electric energy produced in that region via nuclear reactors. However, it should be noted that the costs are often lowered as additional nuclear units are added in an area because of the experience gained in putting the first installation in place, as well as savings in front end expenses. Thus, if one or two units were added at Point Lepreau the unit energy cost in real terms for the entire station would likely be lower than indicated here.

Lingan station in Nova Scotia contains two units in operation (1980-1981), while work on the third unit is in progress with an expected in-service date of 1984. With the third unit the total capacity of the Lingan station will reach 450 MW. The average capital cost of the Lingan station (over three units) will be approximately $882 per kilowatt capacity in real (1981 dollars) terms. This includes interest during the construction period. The operating cost (excluding fuel) is estimated to be $7.7 million per year for all three units. Fuel costs are approximately $51 million. Both operating and fuel costs are also stated in real 1981 dollars and are based on coal price of $55 to $62 per tonne.

Point Lepreau, considered as a single-unit nuclear power station with 630 MW capacity, has an estimated capital cost of $1,928 per kilowatt capacity in real (1981 dollars) terms--including interest on borrowed funds during the construction period. The annual operating

and maintenance cost is estimated at $24 million. The annual fuel cost is estimated to be $15 million.

Table 3.3 shows the cost comparison of the Point Lepreau and Lingan stations. The present values of their unit energy costs have been calculated with a 5 percent discount rate and an 80 percent capacity factor for the base case.

Although delays in the construction of the Point Lepreau nuclear plant have increased the supply price of energy there drastically, the nuclear power alternative to coal appears to provide competitive electrical energy. Table 3.3 shows that nuclear reactors can produce electricity in the Atlantic region on a basis competitive with coal-fired power stations. This is reinforced by the likelihood that the unit generation costs at Lepreau would decline considerably if additional units were built and expectations that the total fuel costs at Lingan will rise substantially through time.

TABLE 3.3

TOTAL UNIT COST OF ELECTRICITY GENERATION
ATLANTIC REGION
($ 1981)

Costs	Coal (mills/kW.h)	Nuclear (mills/kW.h)
Capital	7.42	20.31
Operating & Maintenance	2.80	5.80
Fuel	20.79	6.66
Total	31.01	32.77

SOURCE: Based on data obtained from the New Brunswick Electric Power Commission and Nova Scotia Power Corporation.

NOTE: Average capacity factor = 80%; Discount Rate = 5%.

3.1.2 Quebec

Electric energy demand in Quebec is met mainly by hydroelectric generating stations. There are still a number of economically attractive hydro sites to satisfy the foreseen domestic demand in the province. Coal-fuelled generating stations have not made a major

contribution. This is mainly due to the lack of coal deposits and Quebec's distance from the coal production centers.

The first commercial nuclear reactor, Gentilly 2, is in the final stages of construction and is expected to be in service in 1982. However, for the Quebec comparison, we have utilized cost estimates of an assumed CANDU reactor with 4 x 850 MW capacity and an assumed 4 x 750 MW coal-fuelled generating station. Both were assumed to begin service in 1990. Total capital cost of the CANDU project was estimated at $4.5 billion. This would yield a capacity cost of about $1,324 per kilowatt in terms of 1981 dollars. The capital cost includes the cost of heavy water and interest during the construction period at 5 percent (real) per annum.

The total capital cost of the coal-fired station was estimated to be $2.8 billion. This translates into a capacity cost of $933 per kilowatt. The fact that Quebec does not have coal deposits reduces the economic spinoffs of such equipment. The unit energy costs nuclear reactor and coal-fuelled power plants are shown in Table 3.4.

TABLE 3.4

TOTAL UNIT COST OF ELECTRICITY GENERATION
QUEBEC
($ 1981)

Costs	Coal (mills/kW.h)	Nuclear (mills/kW.h)
Capital	8.65	16.01
Operating & Maintenance	4.25	3.55
Fuel	21.16	6.67
Total	34.06	26.23

SOURCE: Based on data obtained from Quebec Hydro.

NOTE: Average capacity factor = 80%; Discount Rate = 5%.

The fuel cost of the coal-fuelled power plants could be extremely expensive relative to nuclear. This reflects the fact that Quebec not only has no coal deposits suitable for this purpose, but that the neighbouring provinces are also poor in that respect. The transportation cost for coal would comprise more than 60 percent of the cost of coal imported by Quebec from western Canadian deposits. The

fuel cost for Quebec's assumed coal-fired units was based on a coal price of $67 to $72 dollars per tonne (1981 dollars). The annual fuel cost for this station is estimated at $347 million. The estimated annual fuel cost for the nuclear reactors is $151 million. Operating and maintenance cost is estimated at $84 million per year.

3.1.3 Ontario

Present electricity is supplied by a mixture of hydro, nuclear, and coal-fired power plants in Ontario. Less than 5 percent of total electric energy in Ontario is produced from oil and natural gas combustion. Nuclear power and coal's contribution to electricity generation are 35 percent and 28 percent, respectively. Ontario Hydro, with 72 reactor-years of operating experience, is the Canadian utility most experienced with nuclear power and one of the most experienced utility companies in the world in that regard. Installed nuclear capacity in Ontario is 5 248 MW and an additional 12 reactors (8 612 MW) are under construction or planned. Ontario's experience with the CANDU reactor has been a success not only in terms of economic development but also in terms of reliability, environmental and safety attributes.

For the purpose of this study the lifetime costs of a 4 x 850 MW CANDU generating station in Ontario were compared to those for a 4 x 500 MW Canadian bituminous coal-fired generating station using western Canadian Coal. Ontario Hydro has published a study in which cost estimates of these two alternatives are discussed.[5] In the Hydro study, a third alternative, i.e., a coal-fuelled station using U.S. coal, is also discussed. Since imported coal from the U.S. contains normally 2 percent to 2.5 percent sulfur, it is necessary to add scrubbers to meet the present environmental standards. The recent concern over 'acid rain' has increased the likelihood that flue gas desulfurization equipment will be required on future coal-fuelled generating stations. It is estimated that flue gas desulfurization equipment would reduce sulfur emission by 90 percent. Western Canadian coal contains only 0.3 percent to 0.6 percent sulfur for heat output equivalent to United States coal.

Total investment cost of the coal-fuelled station with 4 x 500 MW capacity was estimated to be $1,841 million (in terms of 1981 dollars and a 3 percent real discount rate). The in-service date was assumed to be 1988, with a construction period of five years. The investment cost for a 4 x 850 MW nuclear plant was assumed to be $4 billion in 1981 dollar terms, also with a 3 percent real discount rate. Of this amount $1,355 million would be required for heavy water

equipment. A construction period of seven years, with a 1988 in-service date, was assumed. The shorter construction period for both coal and nuclear plants in Ontario is mainly due to the fact that Ontario has had more experience than, for example, Quebec with both alternatives. The cash flow during the construction was based on Table 3.1.

The cost per kilowatt of capacity for the nuclear plant was estimated at $1,190 in 1991 dollar terms. The analogous figure for the coal-fuelled station was $918. The annual fuel costs for the nuclear and coal-fired plants were $132 and $230 million, respectively. The fuel costs for coal stations are based on a western Canadian coal price of $60 to $65 per tonne. The western Canadian coal is almost competitive with imported coal from the United States. This is mainly due to the lower exchange rate in the past few years. The annual operating and maintenance cost of these two plants was estimated to be $83 and $23 million for nuclear and coal-fuelled stations.

Total unit energy costs of coal and nuclear alternatives are shown in Table 3.5.

TABLE 3.5

TOTAL UNIT COST OF ELECTRICITY GENERATION
ONTARIO
($ 1981)

Costs	Coal (mills/kW.h)	Nuclear (mills/kW.h)
Capital	9.27	12.50
Operating & Maintenance	1.68	3.53
Fuel	20.25	6.12
Total	31.20	22.15

SOURCE: Based on data from Ontario Hydro

NOTE: Average capacity factor = 80%; Discount Rate 5%.

3.1.4 Manitoba

Manitoba Hydro has adopted a long-range generation planning process to develop new sources to meet projected electricity demand.

As an outcome of this process, the utility has completed a careful examination of the best thermal power source. This study concluded that coal is the only viable (economically and politically) fuel source for conventional thermal generation in Manitoba. The Manitoba Hydro study also concluded that a 2 x 375 MW coal-fired station would be the most viable size for Manitoba at this time. This station would have an approximate capital cost of $503 million (1981 constant dollars), i.e., capacity cost of $670 per kilowatt. This may be an optimistic estimate as capital costs could be at least 50 percent higher. However, for the purpose of our study we have used data given by Manitoba Hydro.

The Manitoba coal-fuelled station costs are based on the assumption that the station would burn low-sulfur western Canadian coal, thus flue gas desulfurization equipment (FGD) costs are not included in the station's capital cost. Manitoba Hydro's study shows that if FGD were required by environmental regulations, an additional capital cost of $135 per kilowatt would be necessary. This cost corresponds to 70 percent SO_2 removal efficiency. FGD would also lower the energy production of the station by about 3 percent.

Expenditures over the construction period were assumed to be as the following schedule:

TABLE 3.6

CAPITAL COST OUTLAY SCHEDULE FOR COAL-FIRED AND NUCLEAR STATIONS IN MANITOBA (percentage of total)

	Coal-Fuelled	Nuclear
Year One	6	7
Year Two	11	13
Year Three	32	19
Year Four	31	28
Year Five	14	27
Year Six	6	6

SOURCE: Manitoba Hydro, SPD-80-25

A similar study by Manitoba Hydro on the nuclear option concluded that the most attractive nuclear power source would be a 2 x 600 MW CANDU-PHW nuclear generating station. Capital cost of the station would be $1,642 million (1981 dollars) or $1,368 per kilowatt.

Nuclear-generated electricity, which compares favourably with other alternatives, will become increasingly attractive in the future as the economic hydro sites are developed and the cost of fossil-fuels continue to escalate. More important than the cost of electricity produced by a nuclear generating station is its potential to reduce the overall cost of energy produced by the system as a whole. For example, because a nuclear station would improve the utilization of water, it would enable the hydro-electric stations on the Manitoba Hydro system to be 'over-built' for peaking at a low incremental cost. It would also reduce the need for water-storage.

The cash flow schedule for capital cost expenditures relating to a nuclear plant is given in Table 3.6.

The results of the total unit energy cost comparison calculations are shown in the following table:

TABLE 3.7

TOTAL UNIT COST OF ELECTRICITY GENERATION
MANITOBA
($ 1981)

Costs	Coal (Mills/kW.h)	Nuclear (Mills/kW.h)
Capital	6.77	12.70
Operating & Maintenance	2.88	4.54
Fuel	28.77	7.60
Total	38.42	24.84

SOURCE: Based on data from Manitoba Hydro

NOTE: Average capacity factor = 80%; Discount Rate 5%.

3.1.5 Alberta

As noted earlier, Alberta is a coal-rich province. As a result, the electric utilities in Alberta plan future electric energy generation mainly around coal. At present, all three major utility companies in Alberta have coal-fuelled power plants under construction that are expected to come in-service before the end of this decade. TransAlta Utilities Corporation (formerly Calgary Power) is active in construction of a two-unit coal-fuelled station at Keephills (South

Sundance) and has submitted applications for installation of two more units there.

For the purpose of this study, cost estimates for the Keephills station were taken as representative of coal-fuelled electricity generation costs in Alberta. The Keephills plant will be a mine-mouth generating station with coal supplied from the Highvale mine. Coal will be trucked from the mine to the coal processing plant hoppers where it will be crushed and stored, then conveyed to the generating station bunkers as required. Total nominal capacity of the Keephills station will be 4 x 375 MW.[6] However, only the first two units, now under construction at an estimated capital cost of $665 million (1981), were included in our cost calculations. This investment expenditure includes interest during the seven years of construction period. This yields $887 per kilowatt capacity cost.

The fuel costs estimated for Keephills units 1 and 2 (and incorporated in this study) are only the incremental costs of the Highvale mine production ($6.50 per tonne of coal) since the coal mine is already operational. This may underestimate total unit energy cost of a coal-fired station in Alberta. An alternative would be to calculate coal costs based on the opportunity cost, such as the coal selling price to out-of-province buyers.

With regard to CANDU nuclear reactor costs in Alberta, Manitoba's nuclear costs were taken plus a 10 percent increase in capital and operating costs. The additional 10 percent reflects additional transportation costs for equipment and the higher cost of living in Alberta. The capital cost of nuclear reactors in Alberta, including interest during construction period, would be in the vicinity of $1,512 per kilowatt capacity in terms of 1981 dollars. (This is similar to the observation made by Frank F. Foulkes, Chairman of Canatom, in "The Economics of Fossil Fired vs Nuclear in Alberta" presented in Calgary, April 7, 1982, at the Nuclear Information Seminar hosted by Alberta Power and TransAlta Utilities.)

Table 3.8 compares the cost calculations for the two alternatives in Alberta. The base case results show that coal-fuelled electric energy generation is cheaper in Alberta than nuclear.

TABLE 3.8

TOTAL UNIT COST OF ELECTRICITY GENERATION
ALBERTA
($ 1981)

Costs	Coal (mills/kW.h)	Nuclear (mills/kW.h)
Capital	9.54	15.64
Operating & Maintenance	3.16	4.90
Fuel	6.57	8.47
Total	19.27	29.01

SOURCE: Based on data from TransAlta Power Corporation

NOTE: Average capacity factor = 80%; Discount Rate 5%.

3.1.6 British Columbia

B.C. Hydro has considered using Hat Creek coal in the generation of electricity since 1957. Application has now been made to government authorities for the necessary permits and licences to develop a 2000 MW coal-fired power plant which would burn Hat Creek coal. For the purpose of this study, cost estimates for Hat Creek have been taken as representative of a coal-fuelled station in British Columbia.

The construction of the first unit at Hat Creek is expected to start (subject to approval by the B.C. government) early in 1983 and the in-service date is expected to be late in 1988 (a six-year construction period). Total capital investment, including mine capital expenditure, is estimated to be over $5 billion (escalated). This includes 100 percent removal of the sulfur from coal. Capital cost would be reduced by $0.56 billion if the scrubbers were not installed. The capital expenditure figures include interest on incurred expenditures during the construction period. To control particular emission, the plant would use electrostatic recipitators. For sulfur dioxide control, a high multi-flue stack would be used to disperse the emission.

It should be noted that because capital expenditures for mine development are included in the capital costs of the Hat Creek station, the fuel costs were expressed in an incremental form rather than their unit production cost. Fuel costs were thus based on the estimated $12 per tonne extraction cost for Hat Creek coal mine. Total coal

consumption will be over 40 000 tonnes per day when the plant is operating at full capacity. The annual operating costs would be an estimated 2.41 percent of total capital costs (B.C. Hydro estimates).

The base case total unit energy costs for Hat Creek and for an assumed CANDU nuclear station in British Columbia are shown in Table 3.9. The inclusion of investment on mining in the coal station in capital costs is reflected in a higher capital cost per unit of energy produced than for coal-fired stations elsewhere in the country. It also means that the unit capital cost of the coal station (Hat Creek) would be greater than for a nuclear plant of the sort assumed.

TABLE 3.9

TOTAL UNIT COST OF ELECTRICITY GENERATION
BRITISH COLUMBIA
($ 1981)

Costs	Coal (mills/kW.h)	Nuclear (mills/kW.h)
Capital	16.83	16.11
Operating & Maintenance	4.70	5.62
Fuel	14.87	8.46
Total	36.40	30.19

SOURCE: Based on data from British Columbia Hydro.

NOTE: Average capacity factor = 80%; Discount Rate 5%.

3.2 Transmission Costs

In this section the required transmission lines from the electric generating stations to the market and implicitly their effects on the unit energy cost of electricity generation are discussed. Once an interconnected system of transmission lines has been developed to deliver power from a number of generating plants to a number of major load centers, it becomes difficult to apportion the costs of additions to the transmission system to specific additions of generating capacity.

In this study the bulk-transmission costs (that is, transmission costs from the station to the grid system) have been included in the capital costs, but the grid costs were not added to the unit

energy costs. However, it is obvious that the further the distance of the plant location from the consumption market, the higher are the costs attributed to transmission costs. The latter affects the unit electricity costs directly. This implies that considerations should be given to the type of the plant if certain locations have to be chosen.

For provinces that have to import (either from abroad or from other provinces) the fuel for their coal-fired power stations, it is appropriate to use bulk transmission costs, since the same site, in general, can be used for both coal-fired stations and nuclear power plants. However, this is not the case with provinces with coal reserves. In the latter provinces coal has to be transported to the plant site, located near the consumption market. Otherwise, a transmission line is necessary to supply the electricity generated at coal mine-mouth to the consumption market.

Among the provinces in which transmission costs should be considered in the coal versus nuclear power cost comparison, are Alberta and British Columbia. These provinces have large coal deposits that are far from the populated zones. For the province of Alberta, for example, the costs of the Keephills power station, located at the Wabamun (west of Edmonton) coal mine, were chosen as representative of coal-fired station costs. This station mainly serves the southern part of the province. The study implicitly assumed that the nuclear plant will also be located in the same area. This may not be true since a CANDU reactor could be erected in southern Alberta and, hence, save transmission costs. In this case the costs of nuclear-powered electricity would be favoured.

The same analogy could be used for British Columbia. The Hat Creek coal-fired station is located in the south-central part of that province while the main market for electricity is in the western part of the province. The spread in unit costs between coal-fired and nuclear stations could widen if transmission costs were included in unit energy cost comparisons.

As far as the Atlantic region is concerned, the implicit assumption was that a Point Lepreau type plant would be built at the Lingan site. However, the results would change in favour of nuclear if a Lingan type coal-fired station were to be built at Point Lepreau or the electricity generated at Lingan were to be transmitted to the New Brunswick market.

The costs of transmission lines vary with the type, capacity, and number of circuits as well as other factors such as the terrain

itself. The information collected from British Columbia Hydro and Hydro Quebec indicates that a one-circuit, 750 kV transmission line costs an estimated $350,000 per kilometer. It should be noted that the actual cost can range from 30 percent below to 60 percent above the given cost, depending on the length of the line and the nature of the terrain.

3.3 Sensitivity Analysis

The unit energy costs calculated in the previous section are, of course, merely estimates. The actual costs would depend on a number of factors. To obtain an accurate cost figure for each project a more thorough study would be required in which site-specific costs would be taken into consideration in great detail. Each specific site's costs will reflect its characteristics and location. For example, the availability of cooling water, closeness to the fuel source, or closeness to a transmission network, will affect generation costs substantially.

In this section, sensitivity analysis of the variables that comprise the energy generation cost is discussed. Changes from the original cost figures would affect total unit energy costs. Plus or minus changes of 25 percent incorporated into the original estimates of capital, fuel and operating and maintenance costs are considered. The effects of such variations on total unit energy costs are shown in Tables 3.10 to 3.12. These results, as for the base cases, are for a discount rate of 5 percent (real) and an average capacity factor of 80 percent. The latter two factors (discount rate and average capacity factor) also affect the total unit energy cost. Thus, in Appendix A, the sensitivity of the unit cost of electricity generation to changes in the discount rate and average capacity factors is demonstrated in a series of tables. These tables also show the increases and decreases in the capital, fuel and operating and maintenance costs, as well as the original estimates.

As the sensitivity analyses illustrate, the total unit cost of a coal-fired station is less sensitive to variations in capital costs than that of a nuclear plant, with the exception of British Columbia. The reason for the exception is that capital costs of mining are also included in the B.C. capital figures. As a discount rate increases, the capital cost sensitivity of coal-fuelled stations, moves upward. Small variations in the capacity factor have no significant effect on the total energy unit cost of power generation from coal.

TABLE 3.10

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF CAPITAL COSTS, ± 25%
($ 1981, mills/kW.h)

Province	-25%		+25%	
	Coal	Nuclear	Coal	Nuclear
Atlantic	29.15	27.65	32.86	37.80
Quebec	31.90	22.22	36.23	30.22
Ontario	28.88	19.03	33.51	25.28
Manitoba	36.72	21.66	40.11	28.01
Alberta	16.88	25.10	21.65	32.92
British Columbia	32.19	26.16	40.61	34.22

NOTE: Average Capacity Factor = 80%; Discount Rate 5%.

TABLE 3.11

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF FUEL COSTS, ± 25%
($ 1981, mills/kW.h)

Province	-25%		+25%	
	Coal	Nuclear	Coal	Nuclear
Atlantic	25.81	31.07	36.20	34.38
Quebec	28.77	24.55	39.35	27.89
Ontario	26.13	20.62	36.26	23.68
Manitoba	31.22	22.93	45.60	26.73
Alberta	17.63	26.89	20.91	31.13
British Columbia	32.68	28.07	40.12	32.30

NOTE: Average Capacity Factor = 80%; Discount Rate = 5%.

TABLE 3.12

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF OPERATING AND MAINTENANCE COSTS, ± 25%
($ 1981, mills/kW.h)

Province	-25%		+25%	
	Coal	Nuclear	Coal	Nuclear
Atlantic	30.31	31.28	31.70	34.18
Quebec	33.00	25.33	35.13	27.11
Ontario	30.78	21.27	31.62	23.04
Manitoba	37.69	23.69	39.13	25.95
Alberta	18.48	27.78	20.06	30.23
British Columbia	35.22	28.78	37.58	31.59

NOTE: Average Capacity Factor = 80%; Discount Rate = 5%.

The total cost of generating electricity from nuclear power is generally more sensitive to variations in capital cost. As capital costs vary about 25 percent, on the average, the unit energy cost changes by about 20 percent.

The sensitivity results with regard to the fuel costs show the opposite pattern. That is, coal-fuelled stations are very sensitive to changes in fuel cost. Again, British Columbia is an exception because its coal fuel cost does not include capital costs. Average changes in total unit cost caused by $\pm$ 25 percent variation in fuel cost are only about $\pm$ 12 percent in British Columbia and Alberta compared with 20 percent in the most eastern provinces included in the analysis (for the base case). Nuclear stations, on the other hand, are less sensitive to changes in fuel price. The average percentage change is about 10 percent as a result of $\pm$ 25 percent variation in fuel costs.

Neither nuclear power plants nor coal-fired stations are very sensitive to changes in operating and maintenance costs. A $\pm$ 25 percent variation in operating and maintenance costs would generate only about 5 to 7 percent change in total energy unit cost.

By way of summary, higher discount rates and lower capacity factors favour coal-fuelled power plants in terms of lower supply price. The reason for a lower unit cost with a higher discount rate is because of the higher future costs of this alternative. At real discount rates of 8 percent, coal-fuelled electric energy generation is competitive with nuclear energy in the eastern provinces. This is the case even in Ontario.

In Manitoba, Ontario, Quebec, and British Columbia nuclear power is more economical than coal in meeting basic electricity requirements. However, coal-fired stations have the edge in Alberta where they can be located at or near mine-mouth. The results for the Atlantic provinces show that coal-fired stations may generate marginally cheaper electricity than nuclear plants, but transmission cost considerations, additional units at Lepreau, and/or rising coal costs would likely tip the balance in favour of nuclear.

Generally speaking, nuclear reactors produce cheaper electric energy in Canada than coal-fired plants. These results are consistent with studies that have been done in other countries. For example, a study by G. R. Corey on United States' electric energy production from coal and nuclear power shows that, in 1980, 'the bus-bar cost of all coal-fired generation was double that of all nuclear'--36.8 versus 18.4

mills per kilowatt hour. Corey's study also looks at selected nuclear and coal-fuelled stations and reaches the same results.[7]

For more details of the sensitivity of the unit cost determining factors, refer to Appendix A.

Footnotes

[1]Although it was originally planned to include Saskatchewan in this study we were not successful in obtaining the necessary information. Because of confidentiality problems, Saskatchewan Power Corporation was unable to forward the requested data. In the case of nuclear, Saskatchewan unit energy costs are likely close to Manitoba's. Coal-generated electricity might be slighty cheaper than in Manitoba because of fuel costs. Saskatchewan supplies lignite coal to Manitoba.

[2]For the first nine months of 1981 the year-to-date capacity factor for Ontario Hydro's nuclear system was 87.9 percent. Three of the large-scale CANDU reactors had registered capacity factors of better than 90 percent and all eight of the units at Pickering and Bruce scored better than 80 percent.

[3]World uranium prices have dropped dramatically in the last few years. The world uranium price has fallen from $50 (U.S.) two years ago to $27 (U.S.) at time of writing.

[4]New Brunswick Electric Power Commission intends to export over 50 percent of the electricity generated at Point Lepreau to the United States (subject to NEB approval).

[5]"Cost Comparison of 4 x 500 MW Coal-Fuelled and 4 x 850 MW CANDU Nuclear Generating Station." Ontario Hydro, Report No. 595 SP, January, 1981.

[6]TransAlta Utilities Corporation has filed application to the Alberta Energy Resources Conservation Board for two additional units at Keephills. If approved, total nominal capacity will be 6 x 375 MW.

[7]G. R. Corey, "An Economic Comparison of Nuclear Coal and Oil-Fuelled Electric Generation in the Chicago Area", Commonwealth Edision Co., Chicago, January, 1981.

Chapter 4

SUMMARY AND CONCLUDING REMARKS

In the National Energy Program (October, 1980), a number of incentive programs were developed to reduce Canada's dependence on imported oil. Among them is the conversion from heating oil to electricity. Such incentives suggest that electricity demand will continue to grow more rapidly than that for certain other energy commodities, especially oil, in the foreseeable future. With most hydro sites in the country already developed and higher oil prices, alternative fuel sources for electric energy generation are limited. From an economic point of view, nuclear power and coal are among the best alternative fuel sources for this purpose.

The economics of nuclear versus coal in generating electric energy have been examined. The analysis indicates that in Quebec, Ontario, Manitoba and British Columbia nuclear energy is less costly than coal for electric power generation. In the base case scenario the nuclear advantage is 24 percent in Quebec, 29 percent in Ontario, and 34 percent in Manitoba and 16 percent in British Columbia. In Alberta and the Atlantic region, coal has a comparative advantage over nuclear energy in electricity generation. The coal advantage in the base case scenario was about 35 percent in Alberta and 6 percent in the Atlantic region. As noted in Chapter 3, capital cost for the Point Lepreau nuclear station in New Brunswick was higher than expected because of labour problems and boiler defects during the construction period. This suggests that the cost of electric power generation with the nuclear option is lower in Atlantic Canada than the results shown in Table 3.3.

The base case scenario was based on original (or actual) cost estimates with a 5 percent discount rate and an 80 percent capacity factor. To capture the effects of variations in the determining factors, different scenarios were examined incorporating changes in capital, fuel, operating and maintenance costs, discount rates and capacity factors. The computations show that total unit energy cost is sensitive to variations in both capital and fuel costs for both nuclear and coal-fuelled power stations. However, unit energy costs of neither nuclear plants nor coal stations are very sensitive to operating and maintenance costs.

The cost of electricity from nuclear plants is dominated by the capital charges for the plant. At present, over 60 percent of the cost of electricity from nuclear plants is attributed to capital charges. Over the past decade, construction costs of nuclear power plants have risen markedly faster than the rate of inflation. Capital charges are a smaller fraction of the total cost of electricity from coal than from nuclear power plants. Nevertheless, these charges still represent a substantial portion of the cost of coal-generated electricity (35 to 65 percent depending on location). Construction costs of coal plants have also increased in recent years for some of the same reasons as for nuclear plants. In addition, the use of new equipment (scrubbers) to reduce sulfur emissions may increase construction costs as much as 20 to 25 percent.

Fuel cost accounts for the greatest portion of the overall differential between total generating costs of nuclear and coal-fuelled power stations. The coal-fuelled stations are very sensitive to the final price of coal. Since transportation costs comprise a major portion of this cost, they have to be reduced as much as possible. It is advantageous to locate a coal-fired power station so as to minimize the haulage costs of coal over the expected life of the plant. In addition, attention must be paid to the availability of cooling water supplies, the routing of transmission lines from the plant and the suitability of the terrain. Availability of cooling water and transmission lines are also important for nuclear plants. For provinces without coal deposits the availability of port and/or rail facilities is important if coal is to be imported.

At higher discount rates, total unit energy cost is more sensitive to changes in the capital costs. This is particularly true for nuclear stations and Alberta and British Columbia coal stations with high capital expenditure components. Total unit energy cost is also very sensitive to the real discount rate itself. A change of discount rate from 3 percent to 5 percent, for example, defeats the comparative advantage of nuclear energy in Atlantic region (80 percent capacity factor). Generally, higher discount rates improve the advantage of coal power stations because of the higher costs associated with fuel costs in the future.

As far as capacity factors are concerned, lower rates of utilization affect both alternatives almost equally (for a given discount factor and set of cost data). However, it should be noted that, historically, nuclear stations have higher capacity factors than coal stations.

TABLE 4.1

TOTAL UNIT COST OF ELECTRICITY GENERATION
(mills/kW.h)
($1981)

	Atlantic	Quebec	Ontario	Manitoba	Alberta	British Columbia
Coal:						
Capacity	450 MW	4 x 750 MW	4 x 500 MW	2 x 375 MW	4 x 375 MW	4 x 500 MW
Capital	7.42	8.65	9.27	6.77	9.54	16.83
O & M	2.80	4.25	1.68	2.88	3.16	4.70
Fuel	20.79	21.16	20.25	28.77	6.57	14.87
Total	31.01	34.06	31.20	38.42	19.27	36.40
Nuclear:						
Capacity	630 MW	4 x 850 MW	4 x 850 MW	2 x 600 MW	2 x 600 MW	2 x 600 MW
Capital	20.31	16.01	12.50	12.70	15.64	16.11
O & M	5.80	3.55	3.53	4.54	4.90	5.62
Fuel	6.66	6.67	6.12	7.60	8.47	8.46
Total	32.77	26.23	22.15	24.84	29.01	30.19

SOURCE: Tables 3.3, 3.4, 3.5, 3.7, 3.8 and 3.9.

NOTE: Average Capacity Factor = 80%; Discount Rate = 5%.

Table 4.1 summarizes the cost of electricity generation by nuclear power and coal for different regions in Canada. As pointed out in Chapter 3, the results are sensitive to the assumptions made with regard to the handling of electricity transmission and coal transportation costs. For example, in the coal-nuclear comparison for the Atlantic area, the scale would become tipped in favour of the nuclear option if the comparison were between the Lepreau nuclear power station and a coal station of the Lingan type built at the Lepreau site but utilizing coal transported from Nova Scotia.

APPENDIX A

SENSITIVITY ANALYSIS RESULTS

TABLE A.1

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF CAPITAL COSTS
AVERAGE CAPACITY FACTOR = 80%; DISCOUNT RATE = 3%
($ 1981, mills/kW.h)

Province	-25%		Original Estimates		+25%	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Atlantic	28.40	23.87	29.81	27.66	31.22	31.44
Quebec	30.83	19.10	32.45	22.03	34.06	24.94
Ontario	27.76	16.73	29.52	19.06	31.28	21.39
Manitoba	36.28	19.34	37.56	21.72	38.84	24.10
Alberta	15.24	22.27	17.02	25.21	18.80	28.14
British Columbia	29.43	23.33	32.68	26.35	35.92	39.37

TABLE A.2

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF CAPITAL COSTS
AVERAGE CAPACITY FACTOR = 80%; DISCOUNT RATE = 8%
($ 1981, mills/kW.h)

Province	-25%		Original Estimates		+25%	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Atlantic	30.79	34.72	33.45	42.19	36.11	49.67
Quebec	34.20	28.25	37.39	34.30	40.57	40.35
Ontario	31.17	23.34	34.49	27.94	37.81	32.54
Manitoba	37.92	25.95	40.35	30.58	42.78	35.22
Alberta	20.02	30.35	23.53	36.06	27.04	41.77
British Columbia	37.16	31.47	43.06	37.35	48.99	43.23

TABLE A.3

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF CAPITAL COSTS
AVERAGE CAPACITY FACTOR = 60%; DISCOUNT RATE = 3%
($ 1981, mills/kW.h)

Province	-25%		Original Estimates		+25%	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Atlantic	37.87	31.82	39.74	36.87	41.62	41.92
Quebec	41.11	25.47	43.26	29.28	45.42	33.29
Ontario	37.02	22.03	39.63	25.41	41.71	28.52
Manitoba	48.37	25.79	50.08	28.96	51.79	32.14
Alberta	20.33	29.70	22.70	33.61	25.07	37.52
British Columbia	39.25	31.12	43.57	35.13	47.89	39.16

TABLE A.4

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF CAPITAL COSTS
AVERAGE CAPACITY FACTOR = 60%; DISCOUNT RATE = 5%
($ 1981, mills/kW.h)

Province	-25%		Original Estimates		+25%	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Atlantic	38.87	36.87	41.34	43.64	43.81	50.41
Quebec	42.53	29.63	45.42	34.96	48.30	40.30
Ontario	38.51	25.37	41.60	29.54	44.69	33.70
Manitoba	48.95	28.88	51.22	33.11	53.47	37.34
Alberta	22.51	33.46	25.69	38.68	28.87	43.89
British Columbia	42.92	34.88	48.53	40.25	54.14	45.62

TABLE A.5

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF CAPITAL COSTS
AVERAGE CAPACITY FACTOR = 60%; DISCOUNT RATE = 8%
($ 1981, mills/kW.h)

Province	-25%		Original Estimates		+25%	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Atlantic	41.06	46.29	44.60	56.26	48.15	66.22
Quebec	45.61	37.67	49.85	45.73	54.10	53.80
Ontario	41.55	31.12	45.98	37.26	50.41	43.39
Manitoba	50.55	34.60	53.79	40.78	57.03	46.96
Alberta	26.70	40.46	31.38	48.08	36.06	55.69
British Columbia	49.55	41.96	57.43	49.80	65.32	57.64

TABLE A.6

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF FUEL COSTS
AVERAGE CAPACITY FACTOR = 80%; DISCOUNT RATE = 3%
($ 1981, mills/kW.h)

Province	-25%		Original Estimates		+25%	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Atlantic	24.46	25.98	29.81	27.66	35.16	29.33
Quebec	27.01	20.34	32.45	22.03	37.88	23.72
Ontario	24.32	17.51	29.52	19.06	34.72	20.61
Manitoba	30.17	19.82	37.56	21.72	44.95	23.62
Alberta	15.34	23.06	17.62	25.21	18.71	27.35
British Columbia	28.92	24.20	32.68	26.35	36.43	28.49

TABLE A.7

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF FUEL COSTS
AVERAGE CAPACITY FACTOR = 80%; DISCOUNT RATE = 8%
($ 1981, mills/kW.h)

Province	-25%		Original Estimates		+25%	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Atlantic	28.45	40.56	33.45	42.19	38.45	43.83
Quebec	32.29	32.66	37.39	34.30	42.49	35.94
Ontario	29.61	26.44	34.49	27.94	39.37	29.45
Manitoba	33.41	28.69	40.35	30.58	47.28	32.48
Alberta	21.95	33.97	23.53	36.06	25.12	38.14
British Columbia	39.40	35.27	43.06	37.35	46.75	39.43

TABLE A.8

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF FUEL COSTS
AVERAGE CAPACITY FACTOR = 60%; DISCOUNT RATE = 3%
($ 1981, mills/kW.h)

Province	-25%		Original Estimates		+25%	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Atlantic	32.61	34.64	39.74	36.87	46.88	39.10
Quebec	36.02	27.12	43.26	29.28	50.51	31.63
Ontario	32.43	23.35	39.63	25.41	46.30	27.48
Manitoba	40.23	26.43	50.08	28.96	59.93	31.50
Alberta	20.45	30.75	22.70	33.61	24.95	36.47
British Columbia	38.56	32.27	43.57	35.13	48.58	37.99

TABLE A.9

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF FUEL COSTS
AVERAGE CAPACITY FACTOR = 60%; DISCOUNT RATE = 5%
($ 1981, mills/kW.h)

Province	-25%		Original Estimates		+25%	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Atlantic	34.41	41.43	41.34	43.64	48.27	45.84
Quebec	38.37	32.74	45.52	34.96	52.47	37.18
Ontario	34.85	27.50	41.60	29.54	48.35	31.58
Manitoba	41.63	30.58	51.22	33.11	60.81	35.64
Alberta	23.50	35.85	25.69	38.68	27.88	41.50
British Columbia	43.58	37.43	48.53	40.25	53.49	43.07

TABLE A.10

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF FUEL COSTS
AVERAGE CAPACITY FACTOR = 60%; DISCOUNT RATE = 8%
($ 1981, mills/kW.h)

Province	-25%		Original Estimates		+25%	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Atlantic	37.94	54.08	44.60	56.26	51.27	58.44
Quebec	43.05	43.55	49.85	45.73	56.65	47.92
Ontario	39.43	35.25	45.98	37.26	52.49	39.26
Manitoba	44.54	38.25	53.79	40.78	63.04	43.31
Alberta	29.27	45.30	31.38	48.08	33.49	50.85
British Columbia	52.54	47.03	57.43	49.80	62.33	52.57

TABLE A.11

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF OPERATING AND MAINTENANCE COSTS
AVERAGE CAPACITY FACTOR = 80%; DISCOUNT RATE = 3%
($ 1981, mills/kW.h)

Province	-25%		Original Estimates		+25%	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Atlantic	29.11	26.20	29.81	27.66	30.50	29.11
Quebec	31.38	21.15	32.45	22.03	33.51	22.92
Ontario	29.10	18.18	29.52	19.06	29.94	19.94
Manitoba	36.89	20.57	37.56	21.72	38.28	22.87
Alberta	16.23	23.98	17.02	25.21	17.81	26.44
British Columbia	31.51	24.93	32.68	26.35	33.85	27.77

TABLE A.12

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF OPERATING AND MAINTENANCE COSTS
AVERAGE CAPACITY FACTOR = 80%; DISCOUNT RATE = 8%
($ 1981, mills/kW.h)

Province	-25%		Original Estimates		+25%	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Atlantic	32.85	40.75	33.45	42.19	34.16	43.64
Quebec	34.33	33.42	37.39	34.30	28.45	35.19
Ontario	34.07	27.06	34.49	27.94	34.91	29.83
Manitoba	39.63	29.47	40.35	30.58	41.06	31.70
Alberta	22.74	34.86	23.53	36.06	24.32	37.28
British Columbia	41.89	35.97	43.06	37.35	44.26	38.73

TABLE A.13

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF OPERATING AND MAINTENANCE COSTS
AVERAGE CAPACITY FACTOR = 60%; DISCOUNT RATE = 3%
($ 1981, mills/kW.h)

Province	-25%		Original Estimates		+25%	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Atlantic	38.81	34.93	39.74	36.87	40.67	38.81
Quebec	41.85	29.19	43.26	29.28	44.68	30.56
Ontario	38.80	24.24	39.63	25.41	39.92	26.59
Manitoba	49.12	27.43	50.08	28.96	51.04	30.50
Alberta	21.64	31.98	22.70	33.61	23.75	35.24
British Columbia	42.01	33.24	43.57	34.13	45.13	37.03

TABLE A.14

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF OPERATING AND MAINTENANCE COSTS
AVERAGE CAPACITY FACTOR = 60%; DISCOUNT RATE = 5%
($ 1981, mills/kW.h)

Province	-25%		Original Estimates		+25%	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Atlantic	40.41	41.70	41.34	43.64	42.27	45.57
Quebec	44.00	33.78	45.42	34.96	46.84	36.14
Ontario	41.04	28.36	41.60	29.54	42.16	30.71
Manitoba	50.26	31.60	51.22	33.11	52.18	34.62
Alberta	24.63	37.04	25.69	38.68	26.74	40.31
British Columbia	46.97	38.38	48.53	40.25	50.10	42.12

TABLE A.15

LEVELIZED UNIT COST OF ELECTRICITY GENERATION
SENSITIVITY ANALYSIS OF OPERATING AND MAINTENANCE COSTS
AVERAGE CAPACITY FACTOR = 60%; DISCOUNT RATE = 8%
($ 1981, mills/kW.h)

Province	-25%		Original Estimates		+25%	
	Coal	Nuclear	Coal	Nuclear	Coal	Nuclear
Atlantic	43.67	54.34	44.60	56.26	45.54	58.18
Quebec	48.43	44.55	49.85	45.73	51.27	46.92
Ontario	45.42	36.08	45.98	37.26	46.54	38.43
Manitoba	52.84	39.30	53.79	40.78	54.75	42.28
Alberta	30.32	46.45	31.38	48.08	32.43	49.71
British Columbia	55.86	47.96	57.43	49.80	59.01	51.64

APPENDIX B

ENVIRONMENTAL ISSUES

Appendix B

ENVIRONMENTAL ISSUES

In this appendix the major impacts of nuclear and coal-fuelled power stations on society and on the environment are outlined.

The social costs and benefits of a proposed coal-fired or nuclear power generating station are difficult to assess. The greatest difficulty, however, is the uncertain and limited knowledge regarding the effects on health and on the environment of low levels of chemical and radioactive pollution, and the probability of nuclear accidents. Since there is relatively little operating experience with nuclear power, it is impossible to estimate accident probabilities with any precision. Some risks may be unknown. In the case of coal, several hundred years of experience have not produced quantitative understanding of the health consequences. Even less is understood of the possible effects of the carbon dioxide and particulates released during coal combustion on the world's climate.

Apart from health risks due to electricity generation from coal and nuclear power there are also possible financial and amenity losses due to the environmental effects. Financial losses may arise from damage to:

- food production (crop, animal or fish damage, or the expense of damage avoidance)
- building materials (soiling, damage)
- textiles (soiling, damage)
- water supply (contamination)

Amenity losses are those that cannot be directly evaluated such as lost animal, fish or agricultural production, reduced forest growth, etc. A number of studies have been published in the last few years concerning financial and amenity losses.[1] Included in these studies are Waddell (1974), Wyzza (1974), Salmon (1970) and Acres (1974). However, a general economic assessment of these effects is not yet available for Canada.

The range of uncertainty affecting the social cost estimates is so great that the balance between coal and nuclear power could be tipped in either direction. Furthermore, it is unlikely that the principal uncertainties will be resolved in the near future. Therefore, consideration of the social costs and related issues does not provide a basis for overriding the conclusions reached from the foregoing economic analysis of the coal and nuclear alternatives.

B.1 Nuclear: Environmental Impacts

Low, intermediate, and high level radiation are present in all phases of the nuclear fuel cycle after insertion of the fuel into the reactor core. The most concentrated and lethal core of radiation is produced in the reactor core itself. The energy released by the fission of uranium is both thermal, which is sought in the nuclear power case, and high energy radiation in the form of neutrons, α-particles, β-particles and Υ-rays, which must be contained.[2] This radiation emanates from radioactive isotopes which are not only produced in the reactor core but are also significant constituents of uranium mill tailings and spent nuclear fuels.

Except in the event of a major nuclear accident, somatic and genetic effects can be controlled by limiting the exposure time of individuals within power stations, and by ensuring the minimization of the total radiation release to which the entire population is exposed.[3]

The International Commission on Radiological Protection (ICRP) has recommended maximum limits for radiation exposure on the basis of existing evidence (see Table B.1). Canada's Atomic Energy Control Board (AECB) has based its radiation dose limits on these levels. The AECB has also established limits on the genetic dose for the population as a whole. This should be kept below 5 rems per generation (i.e., the dose aggregated over thirty years). Exposure of the general public to radiation caused directly by nuclear power stations is only a small percentage (about 1 per cent) of the recommended maximum levels. There is some controversy surrounding the effects of low level radiation since there is a latency period before the effects may manifest themselves as cancer. However, there is little chance of distinguishing radiation induced cancers from the much larger number of natural cancers.

TABLE B.1

STANDARDS FOR EXPOSURE TO IONIZING RADIATION
(rems per year)

Parts of the Body	Nuclear Workers	Public
Gonads and Bone Marrow	5	0.5
Skin, Thyroid, Bone	30	3.0
Hands, Feet	75	7.5
All Other Organs	15	1.5

SOURCE: Based on data from International Commission on Radiological Protection.

A major reactor accident which caused the release of large amounts of radioactive materials would constitute a serious health and environmental threat. An accident of such magnitude could arise from the failure of several control systems to the overheating and subsequent melting of the nuclear fuel. The latter would allow a substantial quantity of radioactive material to escape into the environment after penetrating several barriers. High dosages of radiation also increase the risk of genetic damage which may become evident in later generations.

In a study by A. C. Upton, it is shown that in normal (non-accident) conditions the hazard from low level background radiation is much greater from that generated by nuclear reactors.[4] The natural background radiation is composed principally of (1) cosmic rays; (2) emissions from the disintegration of uranium, thorium, radium and other radioactive elements in the earth's crust, and (3) emmissions from potassium 40, Carbon 14 and other radioactive isotopes occurring naturally in the body.

B.1.1 Fuel Production - Health and Environmental Concerns

The front end of the CANDU fuel cycle is comprised of the mining and milling of uranium ores to produce uranium oxide (U_3O_8), the disposal of the mill tailings, the refining and fabrication of the uranium oxide into pellets and subsequent assembly into fuel bundles.

The Royal Commission on the Health and Safety of Workers in Mines (The HAM Commission) reported hazards which may induce cancer. These are:

- inhalation of radon gas and the growth of its short-lived products in the mine atmosphere or in an enclosed area
- ingestion and inhalation of uranium concentrates by operators in the precipitation, filtering, drying and packing areas in the mill
- external radiation in the neighbourhood of very high grade ores
- radiation from thorium (four times as abundant as uranium in the rock of the Canadian Shield) as a by-product of milling or from reworked tailings

Since 1954, when uranium mining began in the Elliot Lake region of Ontario, environmental contamination has occurred in the immediate vicinity of the mine resulting from the drainage of highly acidic tailings. The mill tailings are dumped near the mill and have approximately the same bulk as the original ore. Since the early 1970s this acidic drainage has been controlled.

The health and environmental implications of other aspects of the front end of the fuel cycle, such as the transportation of uranium concentrates, fuel elements and bundles, as well as the refining processes, are not considered as serious.

The CANDU reactor incorporates a variety of physical barriers to protect the public from potential radioactive releases. The first barrier is the ceramic uranium oxide (UO_2) fuel pellet itself--most of the radioactive fission products are bound within the UO_2. Subsequent barriers include the zirconium fuel sheaths of the fuel bundles, pressure tubes, the heavy water coolant, the steel calandria and a steel shield tank filled with light water or heavy concrete shielding which surrounds the whole calandria. The complete reactor assembly is located inside a thick, steel-reinforced, prestressed containment building. Many CANDU plants also have a separate vacuum building capable of containing gaseous emissions. Finally, there is an exclusion zone of one kilometre around the reactor building.

Probabilities of the occurrence of major accidents have been estimated. The probability of a core meltdown per reactor at Pickering and Bruce is estimated to be in the order of 1 in 1,000,000 years.[5]

B.1.2 Heavy Water Plants

The heavy water facilities serving the existing nuclear power stations in Canada are located at the Bruce Generating Station in Ontario. In addition to the usual environmental problems associated with large industrial chemical plants--chemical and thermal pollution, oil spills and leakages and sanitary wastes--heavy water plants routinely discharge small quantities of hydrogen sulphide (H_2S). When H_2S is burned in sufficient quantity, sulphur dioxide (SO_2) is created. The greatest health and environmental threats of heavy water plants will arise if large emissions of H_2S occur. These may develop in three instances: failure of the pressure envelope, chemical imbalance in the process, and during start up. Under normal operating conditions, the Bruce heavy water plants meet the environmental standards set for H_2S discharge.

B.1.3 Interim Storage of Spent Fuel

In this section the interim storage (up to forty years) and transportation of spent fuel are considered. The lethality of a freshly removed spent fuel bundle is such that a person standing within a metre of it would receive a lethal radium dose.

Upon removal from a reactor, a spent fuel bundle is transferred by remote control from the fuelling machine to a storage bay within the station. This bay is filled with circulating water to a level at least three metres above the stacked bundles. Sufficient storage space is available in the existing bays to last till the mid 1990s. No additional bays can then be built until a disposal facility is provided.

Transportation of Spent Fuel

The transportation of spent fuel is normally permitted after a five year cooling period in on-site storage bays. The probability of a fatal transportation accident from the release of radioactive material is said to be in the order of 1 in 70 million shipments. More than 500 radioactive shipments have been made in Canada to date, without any significant event.

Ultimate Disposal

The potential health hazards of radioactive wastes and plutonium produced during reactor operation are assigned to nuclear power. Plutonium and other waste components present special problems since they decay very slowly and remain dangerous for thousands of years.

Critics of nuclear power question the morality of creating this threat to future generations or even to future civilizations. For the first 600 years the radioactivity is due almost exclusively to the fission products. For the following 100,000 years, the main radioactive isotopes are plutonium and americium. Since these wastes already exist in substantial quantity, a safe method for their long-term disposal is required regardless of future nuclear developments.

Alternative methods of ultimate disposal of high-level radioactive wastes include burial in stable geological formations such as salt or hard rock, and burial beneath the deep ocean floor. In Canada disposal in hard rock formations such as granite in the Canadian Shield is preferred.[6] However, so far the disposal problem of waste material has not been solved in Canada. A mega project for underground burial in Ontario has been deferred indefinitely.

If solar energy and other alternatives such as fusion energy do not live up to expectations within the next fifty years, a situation may develop in which the reprocessing of CANDU spent fuel might become economic and desirable. Although permanent spent fuel disposal is environmentally optional, it may be necessary to reprocess the current spent fuel for energy for future generations.

B.1.4 Reactor Decommissioning

The economic lifetime of a nuclear reactor has been argued to be between thirty and forty years. Its technical life may be much longer. Subsequently, the spent fuel from the core and storage bays and heavy water from the calandria and cooling circuits must be removed because components of the reactor remain radioactive for many years thereafter. There are two stages for decommissioning a nuclear structure:

(i) Mothballing: involves leaving the containment and cooling systems intact after the final shutdown and keeping the building under surveillance for at least fifty years;

or

Encasement: the readily movable components which remain radioactive longer than the life of the encasement structure are removed and the remaining radioactive components are sealed within the encasement structure and monitored for many years.

This is followed by:

(ii) Dismantling and removal: all radioactive material would be removed from the site and deposited in an ultimate disposal facility.

Each of these stages has a risk element attached.

B.2 Coal: Environmental Impacts

Prior to the enactment of environmental legislation, the principal criteria used in evaluating a coal mining project were economic and engineering feasibility. Today, before a new mining scheme is approved, provincial governments require environmental assessment studies. Air quality objectives and standards have been legislated by the federal government and various provinces. The legislation specifies three levels of concentration--desirable, acceptable and tolerable--above which various pollutants are considered a threat to public health and property and to environmental quality.

The production and use of coal can affect the environment in all of its separate stages. The first stages are exploration, mining and beneficiation. These are followed by transportation and utilization by either combustion, coking or conversion.

Impacts on the environment from each of these stages are summarized in Table B.2.

B.2.1 Effects of Coal Operations

Exploration

Exploration frequently involves cutting lines through wooded areas, establishing trails and roads, clearing drill sites, test-hole drilling, trenching and digging test-pits and drilling exploratory cuts. In the plains areas these activities can usually be carried out with little or no disturbance, while in forested regions the damage is visible for many years.

Mining

Surface mining, in particular, is a potential source of serious and extensive degradation of the environment. It alters the land surface, destroys the original vegetation and often rearranges the order of materials in the soil. The most controversial regulations apply to reclamation of land disrupted by surface mining. Reclamation means the return of disturbed land to a productive use consistent with

TABLE 8.2

POTENTIAL ENVIRONMENTAL DAMAGE FROM COAL MINING

	Air	Water	Land	Solid Waste
Exploration and Extraction	Fuel combustion products Waste pile fires	Leaching of waste piles Erosion and silting of watercourses	Surface mining effects and substances	Underground mining waste
Upgrading	Particulates from fine coal drying Waste bank fires	Plant effluents Leaching of waste piles		Tailing ponds waste
Transportation	Wind-blown dust from railway transport			
Utilization	Power Plant Carbon dioxide Sulphur oxides Nitrogen oxides particulates	Thermal discharges	Aesthetic pollution of landscape	Fly ash and slag Failure of slag heaps

an explicitly stated objective, whereas restoration stipulates the return of the land to its pre-mining condition.

Strip mining is most common in western Canada. It involves complete removal of all material above the coal in a series of narrow bands or strips, one cut at a time. The deposited soil remains as a series of ridges unless subsequently graded or levelled. Returning the land to an agriculturally viable condition may necessitate replacement of topsoil layers and sometimes the next subsoil layer to provide the soil medium in which plant roots can develop.

There are four levels of rehabitation of mined land: natural reclamation, reclamation to wildlife habitat, to livestock grazing standard, or to cereal crop production.

Because of the topography and special characteristics of foothills and mountain coal deposits, open-pit mining is used in place of conventional contour stripping. Overburden and rock, which must be blasted, are removed from the pit areas usually by shovel and truck operations. As there are no mined-out trenches for overburden disposal, the waste material is dumped away from the pits and not replaced. The amount of land affected by roads, mine plant and dump areas is substantially greater than the area of the pits themselves. Forested areas are easily reclaimable through good preplanning and engineering design, but the alpine/sub-alpine elevations above the timberline are difficult to rehabilitate.

Members of the coal industry recognize that it is less costly and more effective to co-ordinate the efforts of engineers, management and reclamation specialists before land disturbance takes place. Preplanning involves developing mining techniques for soil segregation and placement, grading erosion control, water management practices and revegetation schemes.

The effects of underground mining on the environment are much less extensive than those of surface mining. The only visible operations are those associated with surface plant, shops, roads, storage and loading facilities and waste dumps. Except for the latter, space requirements are similar to other industrial plants, and can generally be designed so that they are acceptable in appearance. Storage piles and waste taps may require special design, protection and masking to disguise their appearance.

Drainage of water from underground mines in the western provinces has not been an environmental problem.

Coal Beneficiation

Coal beneficiation operations are designed to meet certain environmental problems. A wet-washing preparation plant producing 8 100 tonnes per day of clean coal requires about 600,000 gallons of water per day to carry out the tailings. Depending on the coal and plant design, much of this water can be reused so that there is no net effluent from the operation. If the discharge contains much clay-like material, recirculation may not be feasible. In such a case fresh water must be provided to the plant, and the effluents discharged must be treated before the water can be released into the general drainage system.

B.2.2 Coal Utilization

Thermal power generation and coal conversion processes can create problems due to the formation of noxious gases and fine particulates, disposal of ash and thermal effects from discharge of cooling water into streams or lakes.

Coal-fired thermal power plants can produce and may discharge three major objectionable substances into the atmosphere: sulfur dioxide, nitrogen oxides (NO_x) and particulate matter or ash. Sulfur dioxide is derived from sulfur compounds in coal, and nitrogen oxides are produced from nitrogen in the coal and from combustion air. Approximately 95 percent of the sulfur in bituminous coal is normally emitted from the stack as SO_2. The stack gas concentrations of SO_2 are 1500-2000 parts per million (PPM) at Ontario Hydro's bituminous coal-fired plants. Most of the NO_x leaves the stack as NO in stack gas concentrations of 500-600 PPM. Electrostatic precipitators remove more than 99 percent of the flyash in the flue gases of coal-fired boilers. It should be mentioned that electrostatic precipitation is not the only method of removing flyash. Other methods such as 'baghouse' are also available.

A proportion of the sulfur emitted by oil-fired plants may be in the form of SO_3 which could form acid mists. The presence of vanadium in coal and the relative absence of ash enhance the formation of SO_3, so that corrective actions are needed. These include low excess-air operation (to minimize oxidization from SO_2 to SO_3), fuel additives (to reduce the catalytic action of vanadium) or stack gas additive(s) (e.g., ammonia to convert SO_3 to ammonium sulfate which is removed by electrostatic precipitators). In these ways, SO_3 emissions can be controlled to low levels.

The effect of sulfur dioxide on man has been thought to result from its combination with H_2O in the respiratory tract to form sulfurous and sulfuric acid. It appears that health effects due to SO_2 can be much more severe in the presence of particulates. Epidemiological studies (Finkler 1974) suggest that sulfate formed from SO_2, rather than SO_2 itself, may be the damaging agent.[6] The mechanism of health damage due to SO_2 and particulates is not understood, yet the evidence for such damage at high ambient concentrations has been strong enough to lead to the establishments of air quality standards for both of these pollutants.

The effect of sulfur oxides on vegetation and soils is apparently due to the formation of acid on moist leaf surfaces, 'acid rain', and to penetration of SO_2 into plant tissues to form various sulfur components. Sulfur oxides are also associated with damage to building and textile materials. Both sulfur and nitrogen oxides are components of 'acid rain' which has caused damage in eastern Canada, the U.S.A. and Europe. The exact source of the acids is not clear, although it is expected that sulfuric and nitric acids may be produced from the sulfur dioxide and the nitrogen oxides present in the polluted air. Even fairly low levels of acid could leach nutrients out of the soil, injure leaf surfaces and otherwise endanger the health of plant, animal and aquatic communities.

Although it is difficult to ascertain the future impact of acid rain on the environment, it is important to realize that any widespread danger to plants and lower animals and hence to the world food chain, should be taken seriously.

Most of the sulfur dioxide produced when coal is burned can be retained within the plant by the use of wet precipitators (scrubbers) which are now required when sulfur emissions exceed air quality standards. Scrubbers can cost in the vicinity of $150 per kilowatt of installed capacity and result in plant efficiency losses. For example, to install a scrubber at the 300 MW thermal generating plant at Poplar River, Saskatchewan, the capital cost is estimated to be $50 million ($167/kW); extra operating costs would be associated with supplying limestone and there would be a 5 percent loss of output power. These additional costs are substantial when compared to the $170 million capital cost ($567/kW) of the project. With few exceptions, western Canada coal has a sulfur content of 0.5 percent or less and sulfur dioxide emission from power plants burning western coals are low enough that scrubbers may not be required with present environmental standards.

Depending on the type of coal and furnace design, some of the ash produced remains in the boiler bottom, a small percentage adheres to other parts of the boiler and the remainder is carried along with the stack gases as fine dust. Electrostatic precipitators have the widest application among particulate removal methods and 99 percent or more of all particulates are removed by them in many modern plants. The efficiency of such precipitators in western plants is diminished by the low sulfur content of the coal. Consequently, fabric filters are necessary in some western installations. Electrostatic precipitators and fabric filters are expensive, the precipitators at Poplar River are costing $6 million.

The ash residue from burning coal may often amount to 10-15 percent of the burned coal volume. Although small markets exist for it, most ash is considered waste and must be either buried in mining areas or used as landfill. Sludge from gas scrubbers also presents a disposal problem mainly due to their volume and their sulfur content. Part of the ash residue could be used for land reclamation. There are also other uses for this ash, for example, in cement production.

A number of other substances are present in coal plant emissions; these include polycyclic hydrocarbons, especially benzopysene fluoride, herylbium, selenium, nickel, carbonyl, cadmium, antimony, bismuth and mercury in the coal fly ash and flue gas. Some of these substances may be carcinogenic.

B.3 Reclamation Costs of Surface Mining

Reclamation costs vary considerably from region to region and mine to mine. Table B.3 illustrates the short-term reclamation costs, in 1981 dollars, attributed to Saskatchewan's Poplar River Power Project.[7] Costs per acre range from zero for natural reclamation to $2,600 per acre for reclamation to cereal crop production, with topsoil replacement. If selective stripping and extra levelling are required, costs range from $500 per acre for natural reclamation to $3,650 per acre for reclamation to cereal production with topsoil replacement.

A United States study in 1976 reported a wide range of cost estimates: between $1,000 and $4,000 per acre for area mining on flat or gently rolling land in the eastern United States ($500 more in the west), and between $1,800 and $5,000 per acre for contour mining. On this basis, reclamation cost for a five-foot seam in the west was computed at 68 cents per tonne and 18 cents per tonne for a twenty-foot thick seam. Of course, costs will vary according to depth of mining and depth of topsoil replacement.[8]

TABLE B.3

SHORT-TERM RECLAMATION COST[a] ANALYSIS,
PROVINCE OF SASKATCHEWAN

Necessary Mining and Reclamation Operations	Natural Reclamation	Reclamation Options				
		Wildlife Habitat	Livestock Grazing		Cereal Crop Production	
			No Topsoil Replacement	Topsoil Replacement	No Topsoil Replacement	Topsoil Replacement
Normal Stripping at $0/acre	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Recontouring:						
Capping at $500/acre		150[b]				
Levelling to rolling topo. at $1,200/acre		400	1,200	1,200		
Levelling to gently rolling topo. at $1,500/acre					1,500	1,500
Topsoil removal and replacement at $1,000/acre				1,000		1,000
Revegetation at $100/acre		100	100	100	100	100
Total Costs Estimate (Cost/Acre)	$ 0	$ 650	$1,300	$2,300	$1,600	$2,600

SOURCE: Saskatchewan Power Corporation. Poplar River: Thermal Power Project Environmental Assessment and Mine Reclamation; Summary Report, September, 1977; also Canada West Foundation, Western Canada's Coal "The Sleeping Giant", November, 1980.

[a]Costs are based on the value of the 1981 dollar.
[b]Cost rounded to $150 from actual estimated value of $167.

In Alberta, before surface mining begins, an applicant for development and reclamation approval is required to provide security of $25,000 for mines other than those designated as 'small'. TransAlta Utilities has reclaimed about 1200 acres in the Wabamun Lake area.

In addition to the costs of reclaiming mined lands, environmental regulations influence activities and costs throughout the entire production process, beginning at the conceptual planning stage and continuing throughout the life of the project. After preparing detailed development and environmental management plans, the developer must apply either to provincial government agencies or to a co-ordinating committee representing several departments. Delays in processing applications escalate both capital and financing costs due to inflation.

An environmental impact assessment is estimated to cost about $250,000 to $300,000.[9] In Alberta, the review period can last up to one and one-half years. It has been estimated that, for a complete coal project including preparation plant, settling ponds, clean air standards and monitoring, the additional environmental control costs would be 10 to 20 percent of the total capital cost.

In the thermal coal sector of the industry this cost will ultimately be passed on to the consumer. In one example, it was estimated that reclamation costs of $0.30 per tonne in the plains area represented an extra cost of about 1 percent to the consumers of electricity.[10]

B.4 Concluding Observations

In this appendix the social and environmental impacts of coal and nuclear power plants have been reviewed. The unanswered question is whether Canada should concentrate on nuclear or coal plants or a mix of the two alternatives. Setting aside economic considerations, this is tantamount to asking whether the environmental and health effects of coal are worse than nuclear plants or vice versa.

Critics of the nuclear power option are primarily concerned about the possibility of catastrophic reactor accidents and the health and environmental problems associated with nuclear wastes. However, Keeny et al, in their study on United States' nuclear issues, concluded that, "on balance, nuclear power has [a] significantly less adverse environmental impact than coal."[11]

The risks from health and environmental hazards in electric energy production are not confined to coal or nuclear power generation.

Other forms of generation also involve such risks. In a study by H. Inhaber it was stated that "the risk from non-conventional energy sources can be as high as, or even higher than, that of conventional sources. In particular, it tends to be considerably higher than that of nuclear power, the newest of the conventional sources; the ratio is, in some cases, as high as 10 to 100."12

Footnotes

[1]It should be noted that some studies have assigned monetary values to human health and life ($100 per injury-day, or 10^6 per fatality). See, for example, P. G. Hill, "The Social Costs of Electric Power Generation," Royal Commission on Electric Power Planning, 1977.

[2]The nuclei of most of the heavy elements and direct fission products encountered in the nuclear fuel cycle are unstable and emit radiation. The principal forms of radiation of biological significance are alpha (α) particles, beta (β) particles, gama (γ) radiation, and neutrons. When these particles penetrate biological or other matter, they give up their energy through a series of collisions with the atoms or nuclei of the molecules making up the biological material. As a result, many molecules are damaged by breaking of the chemical bonds and by the loss of electrons (ionization), which produces further chemical change. Energy is dissipated along the path of the radiation through these processes. A measure of the rate of linear energy transfer is the density of ionization events along this path. High rates of ionization are roughly equivalent to high intensities of local biological damage.

The amount of radiation absorbed in tissue is expressed in rad units (one rad is 10^{-5} joule of energy absorbed per gram of material). The biological damage caused by different types of radiation, however, is only approximately related to the energy deposited, since α particles and neutrons, for example, generally cause more damage per rad than do β- or γ-radiation. To account for this difference another unit, the rem, is used in setting radiological protection standards. By definition, one rad of β or γ radiation has about one rem of biological effectiveness. A rad of α particles is usually assigned a dose equivalent of 20 rem and a rad of neutrons an equivalence of 10 rem.

Rem (roentgen equivalent man) is basically the rad scale multiplied by factors to make it proportional to biological tissue damage whatever the nature and distribution of the radiation received.

[3]Radiation damage is classified in two ways: somatic refers to damage to body tissue, excluding genetic material. Somatic damage may be either acute (immediate) or chronic (delayed), e.g., as in the development of cancer years after radiation exposure. Genetic damage includes damage to reproductive cells, resulting in possible harm to future generations. Effects may be only mildly debilitating, but could be seriously disabling or lethal.

[4]A. C. Upton, "The Biological Effects of Low-Level Ionizing Radiation," Scientific American, Volume 246, No. 2, pp. 41-49.

[5]Royal Commission on Electric Power Planning, "A Race Against Time: Interim Report on Nuclear Power in Ontario" (Toronto, September 1978), p. 78.

[6]J. F. Finkler, et al (1974); "Health Consequences of Sulfur Oxides: Summary and Conclusions Based Upon Community Health and Environmental Surveillance System (CHESS) Studies of 1970-71." U.S. Environmental Protection Agency, Office of Research and Development, May 1974.

[7]Canada West Foundation, Western Canada's Coal: The Sleeping Giant, a report by an independent task force (Calgary: Canada West Foundation, November 1980). These costs were indicated in 1977 dollars and have been inflated to 1980 dollars. Also, Saskatchewan Power Corporation, Poplar River: Thermal Power Project Environmental Assessment and Mine Reclamation; Summary Report (Regina: Saskatchewan Power Corporation, September 1977).

[8]R. E. Mintz, "Strip Mining: A Policy Evaluation," Ecology Law Quarterly 5 (1976), pp. 451-529.

[9]The Sleeping Giant, p. 147.

[10]Ibid., p. 148

[11]S. M. Keeny, et al. Nuclear Power Issues and Choices, p. 20.

[12]H. Inhabor, "Risk on Energy Production," Atomic Energy Control Board, November 1979.

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